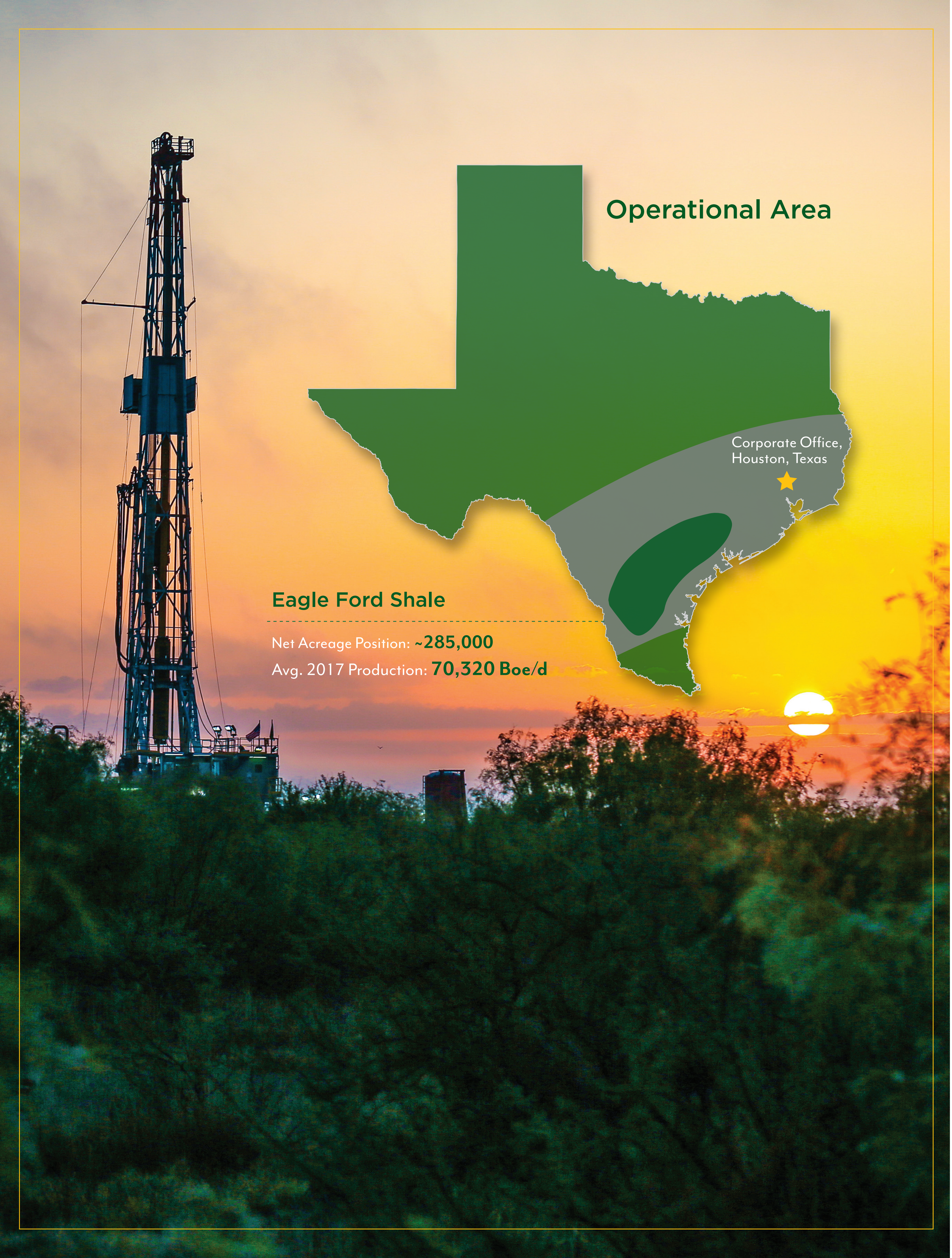
FOCUSED ON

CAPITAL DISCIPLINE AND SHAREHOLDER VALUE

SANCHEZ
ENERGY CORPORATION

2017 Annual Report



Operational Area

Eagle Ford Shale

Net Acreage Position: **~285,000**

Avg. 2017 Production: **70,320 Boe/d**

TO OUR SHAREHOLDERS:

In January 2017, Sanchez Energy, along with Blackstone Energy Partners, announced a 50/50 partnership to acquire a working interest in approximately 318,000 gross operated acres in the Western Eagle Ford – the Comanche asset – for a purchase price, after closing adjustments, of about $2.1 billion. This accretive and transformative acquisition, which came on the heels of a period of significant disruption in the oil and gas industry, set the course for an exciting, demanding, and productive year for Sanchez Energy.

The Comanche acquisition substantially increased our drilling inventory, with more than 1,000 net opportunities identified at the time of the transaction; added 132 gross (33 net) drilled-but-uncompleted wells; and grew the company's operated Eagle Ford position to approximately 585,000 gross acres (335,000 net to Sanchez Energy) in 2017.

COMANCHE WELL RESULTS HAVE SHOWN SIGNIFICANT PROMISE, WITH SOME OF THE HIGHEST INITIAL PRODUCTION RATES IN THE COMPANY'S ASSET BASE.

Our work to integrate the asset was well underway by the time the Comanche transaction closed on March 1, 2017. With careful planning and a deep knowledge of the area, our operations group was able to quickly ramp up drilling and completion activities on the acquired acreage. These 2017 activities, at peak, involved seven drilling rigs and five completion crews at Comanche. As a result, we successfully brought 147 gross (38 net) wells on-line during the year.

Comanche well results have shown significant promise, with some of the highest initial production rates in the company's asset base. Key among these was the Stumberg Ranch 55H well, an approximately 10,000-foot lateral well completed in 2017 with a 30-day peak production rate of approximately 2,900 barrels of oil equivalent per day, 72 percent of which was oil. Additionally, in 2017 we tested longer laterals and stacked development of Lower Eagle Ford wells at Comanche, which led to the addition of approximately 800 gross (200 net) locations to our drilling inventory over the course of the year.

88%

INCREASE IN PROVED RESERVES

The Comanche transaction provides opportunities in our Western Eagle Ford asset base for even greater capital efficiency. As a result, in 2017 we undertook several strategic divestitures to better align our operating footprint and therefore improve operating efficiencies, while providing additional liquidity to operate in today's more challenging price environment. To that end, in June 2017 we closed the divestiture of our non-core Marquis asset for approximately $44 million in cash, plus equity in the buyer, and completed the sale of a 10 percent undivided interest in the Silver Oak II Gas Processing Facility in Bee County, Texas, for $12.5 million. Additionally, in September 2017 we closed the divestiture of our non-core Javelina asset for $105 million, a return of approximately 3.5 times on our investment.

Together, these strategic divestitures, along with borrowing capacity under our credit agreements, provided approximately $589 million in total liquidity to execute our capital plan heading into 2018. Even after the divestitures, we continue to maintain a dominant acreage position in the Western Eagle Ford Shale, with approximately 487,000 gross (285,000 net) leasehold acres and approximately 363 million barrels of oil equivalent of proved reserves, an increase of about 88 percent compared to our proved reserves at the end of 2016. Our acreage is highly concentrated within a 50-mile radius in South Texas and, with approximately 3,700 net drilling locations in the Eagle Ford Shale that comprise our primary development targets, affords us an inventory of more than 15 years of drilling opportunities at our current pace.

Looking to the future, in January 2018 we laid out a shareholder-focused, three-year business plan to help us transition to a sustainable business model that generates free cash flow by 2020. Our three-year plan will allow us to reduce leverage while continuing to deliver organic production growth from our core assets. To help lock in financing for our three-year plan, in February 2018 we issued a $500 million senior secured note and entered into an amended and restated credit facility with borrowing capacity of $25 million to support our ongoing business activities, including hedging. This added liquidity, together with a continuing focus on capital discipline, underpins our efforts to create shareholder value.

Of course, a recap of the last year would not be complete without acknowledging the significant and disruptive impact that Hurricane Harvey had on our employees and the Gulf Coast region of Texas. Throughout the storm, our employees worked tirelessly to support field level operations, maintain production, and serve their communities. Situations like this remind us all how fortunate we are to have a team that, through dedication and positive attitude, can navigate us through any crisis to deliver results. Above all, our human capital distinguishes us from our peers.

OUR THREE-YEAR PLAN WILL ALLOW US TO REDUCE LEVERAGE WHILE CONTINUING TO DELIVER ORGANIC PRODUCTION GROWTH FROM OUR CORE ASSETS.

On behalf of the entire team at Sanchez Energy, thank you for your continued support and investment in our company.

Sincerely,

Antonio R. Sanchez, III
Chief Executive Officer
April 16, 2018

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2017
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 (State or other jurisdiction of incorporation or organization)	**45-3090102** (I.R.S. Employer Identification No.)
1000 Main Street, Suite 3000 **Houston, Texas** (Address of principal executive offices)	**77002** (Zip Code)

Registrant's telephone number, including area code **(713) 783-8000**

Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	New York Stock Exchange
Rights to purchase Series C Junior Participating Preferred Stock, par value $0.01 per share	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a 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 Act). Yes ☐ No ☒

Aggregate market value of the voting and non-voting common equity held by non-affiliates of Registrant as of June 30, 2017: $435,460,057

Number of shares of Registrant's common stock outstanding as of February 23, 2018: 84,839,847.

Documents Incorporated By Reference:

Portions of the Registrant's definitive proxy statement for its 2018 Annual Meeting of Stockholders or an amendment to this Form 10-K, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2017, are incorporated by reference into Part III of this report for the year ended December 31, 2017.

SANCHEZ ENERGY CORPORATION
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2017

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K 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 Annual Report on Form 10-K 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 Annual Report on Form 10-K, words such as "will," "potential," "believe," "estimate," "intend," "expect," "may," "should," "anticipate," "could," "plan," "predict," "forecast," "budget," "guidance," "project," "profile," "model," "strategy," "future" or their negatives or the statements that include these words or other words that convey the uncertainty of future events or outcomes, are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, statements, express or implied, concerning our future operating results and returns or our ability to replace or increase reserves, increase production, or generate income or cash flows, operational and commercial benefits of our partnerships, expected benefits from acquisitions, including the Comanche Acquisition (defined below), 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, including assets acquired in the Comanche Acquisition, 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;

- our ability to effectively integrate acquired crude oil and natural gas properties into our operations, fully identify existing and potential problems with respect to such properties and accurately estimate reserves, production and costs with respect to such properties;

- the extent to which our crude oil and natural gas properties operated by others are operated successfully and economically;

- the use of competing energy sources, 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

- the other factors described under "Item 1A. Risk Factors" in this Annual Report on Form 10-K and any updates to those factors set forth in our subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.

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.

PART I

Item 1. *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 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 December 31, 2017, we had assembled approximately 487,000 gross leasehold acres (285,000 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 Annual Report on Form 10-K in the "Glossary of Selected Oil and Natural Gas Terms."

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 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 "Item 8. Financial Statements and Supplementary Data – Note 2. Basis of Presentation and Summary of Significant Accounting Policies." In addition, on February 14, 2018, we issued $500 million in aggregate principal amount of 7.25% senior secured first lien notes due 2023 (the "7.25% Senior Secured Notes") and amended and restated our 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 "Item 8. Financial Statements and Supplementary Data – Note 20. Subsequent Events". As used in this Annual Report on Form 10-K, "prior revolving credit facility" refers to the Company's revolving credit facility among the Company, certain of its subsidiaries, Royal Bank of Canada, as the administrative agent, and the lenders party thereto, as in effect immediately prior to its amendment and restatement on February 14, 2018, and our "amended and restated credit facility" refers to our revolving credit facility as amended and restated on February 14, 2018.

Listed below is a table of our significant consummated acquisition and divestiture transactions since January 1, 2014:

Transaction	Transaction Date	Transaction Effective Date	Core Area	Net Acreage Acquired	Net Acreage Remaining at 12/31/17	(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	3/1/2017	7/1/2016	Eagle Ford, Pearsall	155,000	155,000	$ (1,039)
Cotulla Disposition	12/14/2016	6/1/2016	Cotulla, Eagle Ford	N/A	N/A	$ 167
Carnero Processing Disposition	11/22/2016	11/22/2016	N/A	N/A	N/A	$ 56
Production Asset Transaction	11/22/2016	7/1/2016	Palmetto and Cotulla, Eagle Ford	N/A	N/A	$ 26
Carnero Gathering Disposition	7/5/2016	7/5/2016	N/A	N/A	N/A	$ 37
Western Catarina Midstream Divestiture	10/14/2015	10/14/2015	Catarina, Eagle Ford	N/A	N/A	$ 346
Palmetto Disposition	3/31/2015	1/1/2015	Palmetto, Eagle Ford	N/A	N/A	$ 83
Catarina Acquisition	6/30/2014	1/1/2014	Catarina, Eagle Ford	106,000	106,000	$ (557)

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 and is subject to normal and customary post-closing adjustments.

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 approximately $44.0 million in cash, after preliminary closing adjustments, 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 and is subject to normal and customary post-closing adjustments.

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, and is subject to normal and customary post-closing purchase price adjustments.

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 County, Frio County, LaSalle County, Zavala County and McMullen County, 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 settlement adjustments were made to the purchase price, which resulted in total aggregate consideration of approximately $167.4 million.

Carnero Processing Disposition

On November 22, 2016, the Company, through SN Midstream, LLC ("SN Midstream"), a wholly-owned subsidiary of the Company, sold its membership interests in Carnero Processing, LLC ("Carnero Processing"). a joint venture that is 50% owned by Targa Resources Corp. (NYSE: TRGP) ("Targa"), to SNMP for an initial payment of approximately $55.5 million and the assumption by SNMP of remaining capital commitments to Carnero Processing which were estimated on the transaction closing date to be approximately $24.5 million (the "Carnero Processing Disposition"). The Carnero Processing Disposition purchase price was determined through arm's length negotiations between the Company and SNMP, including independent committees of both entities.

Production Asset Transaction

On November 22, 2016, the Company, through two of its wholly-owned subsidiaries, SN Cotulla and SN Palmetto, LLC ("SN Palmetto"), completed the sale of certain non-core producing oil and gas assets, located in South Texas, to SNMP for an adjusted purchase price of approximately $24.2 million in cash (the "Production Asset Transaction"). The Production Asset Transaction included the disposition of working interests in 23 producing Eagle Ford wellbores located in Dimmit, LaSalle and Zavala counties in South Texas together with escalating working interests in an additional 11 producing wellbores located in the Palmetto Field in Gonzales County, Texas to SNMP. The effective date of the Production Asset Transaction was July 1, 2016. The purchase price was determined through arm's length negotiations between the Company and SNMP, including independent committees of both entities.

Carnero Gathering Disposition

On July 5, 2016, the Company, through SN Midstream, sold its membership interests in Carnero Gathering, LLC ("Carnero Gathering"), a joint venture that is 50% owned by Targa, to SNMP for a purchase price of approximately $37.0 million and the assumption by SNMP of remaining capital commitments to Carnero Gathering, which were estimated on the transaction closing date to be approximately $7.4 million (the "Carnero Gathering Disposition"). In addition, SNMP is required to pay the Company a monthly "earnout" based on natural gas received at Carnero Gathering's Raptor Gas Processing Facility receipt points from the Company and natural gas delivered and processed at the Raptor Gas Processing Facility by other producers. The purchase price was determined through arm's length negotiations between the Company and SNMP, including independent committees of both entities.

Western Catarina Midstream Divestiture

On October 14, 2015, the Company and SN Catarina, LLC ("SN Catarina") completed the sale of SN Catarina's interests in Catarina Midstream, LLC, a wholly-owned subsidiary of SN Catarina ("Catarina Midstream"), which as of the closing included certain midstream gathering lines and associated assets and interests located in Dimmit County and Webb County, Texas and 105,263 SNMP Common Units to SNMP for an adjusted purchase price of $345.8 million in cash (the "Western Catarina Midstream Divestiture"). In connection with the closing of the Western Catarina Midstream Divestiture, the Company entered into a Firm Gathering and Processing Agreement (the "Gathering Agreement") on October 14, 2015 for an initial term of 15 years under which production from approximately 35,000 acres in Dimmit County and Webb County, Texas have been dedicated for gathering by Catarina Midstream. In addition, for the first five years of the Gathering Agreement, we are required to meet a minimum quarterly volume delivery commitment of 10,200 Bbl per day of crude oil and condensate and 142,000 Mcf per day of natural gas, subject to certain adjustments. We are required to pay gathering and processing fees of $0.96 per barrel for crude oil and condensate and $0.74 per Mcf for natural gas that are tendered through the gathering system, in each case, subject to an annual escalation for a positive increase in the consumer price index. In addition, we have, under certain circumstances, a right of first refusal during the term of the agreement and afterwards with respect to dispositions by Catarina Midstream of its ownership interest in the gathering system. The purchase price was determined through arm's length negotiations between the Company and SNMP, including independent committees of both entities.

Palmetto Disposition

On March 31, 2015, the Company completed the disposition to a subsidiary of SNMP of escalating amounts of partial working interests in 59 wellbores located in Gonzales County, Texas for an adjusted purchase price of approximately $83.4 million (the "Palmetto Disposition"). We received consideration consisting of approximately $81.4 million in cash, after purchase price adjustments, and 1,052,632 SNMP common units valued at approximately $2.0 million as of the date of the closing, which units were subsequently sold back to SNMP in connection with the Western Catarina Midstream Divestiture. The effective date of the Palmetto Disposition was January 1, 2015. The aggregate average working interest percentage initially conveyed was 18.25% per wellbore and, upon January 1 of each subsequent year after the closing, the working interest of the purchaser will automatically increase in incremental amounts according to the purchase agreement until January 1, 2019, at which point the purchaser will own a 47.5% working interest, and the Company will own a 2.5% working interest in each of the wellbores.

Catarina Acquisition

On June 30, 2014, the Company completed the acquisition of 106,000 net contiguous acres in Dimmit, LaSalle and Webb Counties, Texas in the Eagle Ford Shale from SWEPI LP and Shell Gulf of Mexico Inc. for an adjusted purchase price of approximately $557 million (the "Catarina Acquisition"). The effective date of the Catarina Acquisition was January 1, 2014. All proved reserves in the Catarina area are covered under lease acreage that is held by production, which acreage amounted to approximately 29,000 acres at the time of closing. Under the lease we have a 100% working interest and 75% net revenue interest in the lease acreage over the Eagle Ford Shale formation from the top of the Austin Chalk formation to the base of the Buda Lime formation. The undeveloped acreage acquired in the Catarina Acquisition 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 period on a well for well basis. The lease also created a customary security interest in the production therefrom in order to secure royalty payments to the lessor and other lease obligations. Our current capital budget and plans include drilling at least the minimum annual well requirement necessary to maintain access to such undeveloped acreage.

Our Business Strategies

Our primary business objective is to increase reserves, production and cash flows at an attractive return on invested capital. Our business strategy is currently focused on developing long-life, unconventional oil, condensate, NGLs and natural gas reserves from the Eagle Ford Shale as well as other projects that directly enhance the economics of our oil and natural gas operations. Key elements of our business strategy include:

- ***Efficiently develop our Eagle Ford Shale leasehold positions.*** We intend to efficiently drill and develop our acreage position to maximize the value of our resource potential. At December 31, 2017, approximately 51% of our proved reserves were proved undeveloped. As of December 31, 2017, we had 831 net wells and had identified over 3,700 net locations in our Eagle Ford Shale area that comprise our primary development targets. In 2018, we plan to invest between $420 million and $470 million, nearly 90% of which is allocated to drilling and completion activity, with approximately 50% of the drilling completion budget allocated to our Catarina area, 45% allocated to our Comanche area, and 5% allocated to our Maverick area. The remaining 10% of our capital budget has been allocated to leasing, geological and geophysical activities, facilities and other capital expenditures.

- ***Enhance returns by focusing on operational and cost efficiencies.*** We are focused on the continued improvement of our operating measures and have significant experience in successfully converting early-stage resource opportunities into cost-efficient development projects. We believe the magnitude and concentration of our acreage within our core project areas provide us with the opportunity to capture economies of scale, including the ability to directly procure goods and services from manufacturers, drill multiple wells from a single pad, utilize centralized production and fluid handling facilities and implement a line-management approach to improve efficiencies in drilling and completions. In addition, we focus on midstream and other projects that serve our production and add optionality to end markets, ultimately enhancing our realized prices.

- ***Adopt and employ leading drilling and completion techniques.*** We are focused on enhancing our drilling and completion techniques to maximize recovery of reserves. Industry methods with respect to drilling and completion have significantly evolved over the last several years, resulting in increased initial production rates and recoverable hydrocarbons per well through the implementation of longer laterals, more tightly spaced fracture stimulation stages and larger proppant volumes. We evaluate industry drilling results and monitor the results of other operators to improve our operating practices, and we expect our drilling and completion techniques to continue to evolve.

- ***Leverage our relationship with our affiliates to expand unconventional assets.*** SOG, headquartered in Houston, Texas, is a privately owned full service oil and natural gas company engaged in the exploration and development of oil and natural gas primarily in the South Texas, Louisiana and onshore Gulf Coast areas on behalf of certain of its affiliates, including the Company, pursuant to existing management services agreements. The Company refers to SOG and its affiliates (excluding Sanchez Energy), collectively, as the "Sanchez Group." Various members of the Sanchez Group have drilled or participated in over 4,000 wells, directly and through joint ventures, and have invested substantial amounts of capital in the oil and natural gas industry since 1972. During this period, they have carefully cultivated relationships with mineral and surface rights owners in and around our core areas and compiled an extensive technological database that we believe gives us a competitive advantage in acquiring additional leasehold positions in these areas. We have unrestricted access to the proprietary portions of the technological database related to our properties and SOG is otherwise required to interpret and use the database for our benefit. We plan to leverage our affiliates' expertise, industry relationships and size to opportunistically expand reserves and our leasehold positions in the Eagle Ford Shale and other onshore unconventional oil, condensate, NGL and natural gas resources.

- ***Pursue strategic acquisitions to grow our leasehold position in the Eagle Ford Shale and seek opportunistic entry into new basins.*** We believe that we will be able to identify and acquire additional acreage and producing assets in the Eagle Ford Shale at attractive valuations by leveraging our longstanding relationships in and knowledge of South Texas. We may also selectively target additional domestic basins that would allow us to employ our strategies on attractive positions that we believe are similar to our Eagle Ford Shale acreage.

- ***Maintain substantial financial liquidity and flexibility.*** As of December 31, 2017, we had a liquidity position of approximately $588.9 million, consisting of approximately $184.4 million of cash and cash equivalents, $250 million of available borrowing capacity at the elected commitment amount under our prior revolving credit facility, and $154.5 million in available borrowing capacity at the elected commitment amount under our SN UnSub Credit Agreement (defined in "Item 8. Financial Statements and Supplementary Data – Note 6. Debt"). On February 14, 2018, we issued $500 million in aggregate principal amount of our 7.25% Senior Secured Notes and amended and restated our prior revolving credit facility. See "Item 8. Financial Statements and Supplementary Data – Note 20. Subsequent Events." We continually evaluate our level of operating activity in light of commodity prices, our cost structure and other considerations, and, based upon this evaluation, may adjust our capital spending as appropriate. In addition, we expect to continue to regularly review acquisition opportunities from third parties or other members of the Sanchez Group. We have entered into and intend to continue executing hedging transactions for a significant portion of our expected production to achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in oil and natural gas prices.

Our Competitive Strengths

We believe the following competitive strengths will allow us to successfully execute our business strategies:

- ***Geographically concentrated leasehold position in the Eagle Ford Shale.*** We have assembled a current leasehold position of approximately 285,000 net acres in the Eagle Ford Shale, which we believe to be one of the highest rate of return unconventional oil and natural gas formations in North America. Our geographically concentrated acreage position allows us to establish economies of scale with respect to drilling, production, operating and administrative costs, in addition to further leveraging our base of technical expertise in our project areas. We believe that our recent well results and offset operator activity in and around our project areas have significantly de-risked our acreage position such that there are low geologic risks and ample repeatable drilling opportunities across our core operating areas.

- ***Proven low cost operator.*** We are recognized as one of the lowest cost operators in the Eagle Ford Shale. We utilize a combination of initiatives that have improved the efficiency of our operations and reduced the cost of sourcing goods and services. The Company has implemented systems and processes that provide greater coordination across our organization, thereby minimizing inefficiencies from repetitive tasks. We have also segmented and optimized each step in drilling and completing our wells. In addition, our supply chain management team takes a rigorous and methodical approach to reducing the total delivered cost of purchased goods and services by examining costs on their most basic level. As a result, goods and services are commonly sourced directly from suppliers. Additionally, we constantly review the value chain for opportunities to internally provide services in order to further reduce, or provide sustainability in, current costs.

- ***Demonstrated ability to drive liquids production and reserves growth.*** Our average production for full year 2017 was approximately 70,320 Boe/d, substantially all of which was from the Eagle Ford Shale. This compares to approximately 53,358 Boe/d for the full year 2016. Our total proved reserves at December 31, 2017 were 362.7 MMBoe, an increase of approximately 88% over the prior year.

- ***Large multi-year oil-weighted drilling inventory.*** As of December 31, 2017, we had an inventory of over 3,700 net locations for potential future drilling on our acreage position in the oil, natural gas and condensate, or black oil and volatile oil and natural gas, windows of the Eagle Ford Shale.

- ***Experienced management and strong technical team.*** Our team is comprised of individuals with a long history in the oil and natural gas business, and a number of our key executives have prior experience as members of public company management teams. Furthermore, members of the Sanchez Group have a 40-plus year operating history in the areas in which we operate, providing us with extensive knowledge of the basins and the ability to leverage longstanding relationships with mineral owners. Through SOG, we have access to an experienced staff of oil and natural gas professionals including geophysicists, geologists, drilling and completion engineers, production and reservoir engineers and technical support personnel. SOG's technical team has significant experience and expertise in applying the most sophisticated technologies used in conventional and unconventional resource style plays including 3-D seismic interpretation capabilities, horizontal drilling, comprehensive multi-stage hydraulic fracture stimulation programs and other exploration, production and processing technologies. We believe this technical expertise is integral to successful development of our assets, including defining new core producing areas in emerging plays.

Core Properties

Eagle Ford Shale

We and our predecessor entities have a long history in the Eagle Ford Shale, where, as of December 31, 2017, we have assembled approximately 487,000 gross leasehold acres (approximately 285,000 net acres) and have over 8,000 gross (3,700 net) specifically identified drilling locations for potential future drilling. As of December 31, 2017, approximately 748 of these drilling locations represented proved undeveloped reserves. These locations were developed using existing geologic and engineering data. The approximately 7,252 additional gross drilling locations are specifically identified non-proven locations that have been identified by our management team. Although these approximate 7,252 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. See Item 1A. Risk Factors – "Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling." 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) acres in Dimmit, Webb, La Salle, Zavala and Maverick Counties, Texas through the Comanche Acquisition representing a 24% working interest, which we refer to as the Comanche area. We anticipate drilling, completion and facilities costs on our 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 11,100 feet. We have identified greater than 5,300 gross (1,300 net) Eagle Ford locations for potential future drilling on our Comanche area. For the year 2018, we plan to spend $145 million to $150 million to spud 33 net wells and complete 19 net wells in our Comanche area. Additionally, we anticipate spending $40 million to $50 million to complete an additional 21 net drilled-but-uncompleted wells ("DUCs").

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 our 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 December 31, 2017, 50 wells had been drilled towards the 60 well commitment that will end on August 31, 2018. In addition, 129 DUCs acquired as part of the Comanche Acquisition had commenced completions operations, and 105 of those DUCs had been brought online. These DUCs do not count toward the annual development obligation. 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 we refer to as the Catarina area. We anticipate drilling, completion and facilities costs on our 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 11,000 feet. We have identified greater than 1,150 gross (1,150 net) locations for potential future drilling on our Catarina acreage. For the year 2018, we plan to spend $205 million to $215 million to spud 44 net wells and complete 44 net wells in our Catarina area.

In the Catarina area, we have a drilling obligation that requires us to drill (i) 50 wells in each 12-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 12-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 December 31, 2017, SN had drilled 10 wells in addition to the 30 wells banked towards the annual well commitment in the Catarina area that extends from July 1, 2017 to June 30, 2018.

We have approximately 110,000 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 $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 9,500 feet to approximately 10,000 feet. We have identified greater than 1,050 gross (1,000 net) locations for potential future drilling on our Maverick area. For the year 2018, we plan to spend $15 million to $25 million to spud 3 net wells and complete 3 net wells in 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 between $5.5 and $6.0 million per well based on our current estimates and historical well costs. We have identified greater than 440 gross (215 net) locations for potential future Eagle Ford drilling in our Palmetto area. For the year 2018, we plan to spend $2 million to spud 1 net well in our Palmetto area.

Tuscaloosa Marine Shale

As of December 31, 2017, we owned approximately 37,000 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.

Oil and Natural Gas Reserves and Production

Internal Controls

Our estimated reserves at December 31, 2017 were prepared by Ryder Scott Company, L.P. ("Ryder Scott"), our independent third-party reserve engineers pursuant to their report dated January 10, 2018, which is filed as an exhibit to this Annual Report on Form 10-K. We expect to continue to have our reserve estimates prepared semi-annually by Ryder Scott. Our internal professional staff works closely with Ryder Scott to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. All of the reserve information maintained in our reserve engineering database is provided to the external engineers. In addition, we provide Ryder Scott other pertinent data, such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make all requested information, as well as our pertinent personnel, available to the external engineers as part of their evaluation of our reserves.

Technology Used to Establish Reserves

Under SEC rules, proved reserves are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs, and under existing economic conditions, operating methods and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

To establish reasonable certainty with respect to our estimated proved reserves, Ryder Scott employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. These wells were considered to be analogous based on production performance from the same formation and completion using similar techniques.

Qualifications of Responsible Technical Persons

Internal SOG Engineers. Daniel Furbee is the technical person primarily responsible for overseeing the preparation of our reserve estimates. Mr. Furbee has over a decade of industry experience with positions of increasing responsibility in engineering and evaluations with companies such as Baker Hughes and LINN Energy. He holds a Bachelor of Science Petroleum Engineering degree from Marietta College and a Master of Business Administration degree from the University of Houston. Mr. Furbee is a Registered Professional Engineer in the State of Texas.

Independent Reserve Engineers. Ryder Scott is an independent oil and natural gas consulting firm. No director, officer or key employee of Ryder Scott has any financial ownership in any member of the Sanchez Group or us. Ryder Scott's compensation for the required investigations and preparation of its report is not contingent upon the results obtained and reported, and Ryder Scott has not performed other work for SOG or us that would affect its objectivity. The engineering information presented in Ryder Scott's report was overseen by Eric Nelson, P.E. Mr. Nelson is an experienced reservoir engineer having been a practicing petroleum engineer since 2002. He has more than 12 years of experience in reserves evaluation with Ryder Scott. He has a Bachelor of Science degree in Chemical Engineering from the University of Tulsa and Master of Business Administration degree from the University of Texas. Mr. Nelson is a Registered Professional Engineer in the State of Texas.

Estimated Proved Reserves

The following table presents the estimated net proved oil and natural gas reserves attributable to our properties and the standardized measure amounts associated with the estimated proved reserves attributable to our properties as of December 31, 2017, based on a reserve report prepared by Ryder Scott, our independent reserve engineers. The standardized measure amounts shown in the table are not intended to represent the current market value of our estimated oil and natural gas reserves.

	As of December 31, 2017				
	Oil (MMBbl)	Natural Gas Liquids (MMBbl)	Natural Gas (Bcf)	Total Estimated Proved Reserves (MMBoe)(2)	PV-10 (in millions)(3)
Reserve Data [1]:					
Estimated proved reserves by project area:					
Eagle Ford					
Comanche EF[5]	53.7	49.5	296.6	152.6	$ 791.5
Catarina	51.6	61.2	469.0	191.0	851.9
Maverick	12.8	0.2	1.2	13.2	192.8
Palmetto	3.3	0.7	4.4	4.8	35.9
Total Eagle Ford	121.4	111.6	771.2	361.6	1,872.1
TMS	0.3	—	—	0.3	4.5
Other Assets	0.7	0.1	0.4	0.8	9.5
Total	122.4	111.7	771.6	362.7	$ 1,886.1
Standardized Measure (in millions) [1][4]					$ 1,886.1
Estimated proved developed reserves by project area:					
Eagle Ford					
Comanche EF[5]	29.6	32.1	192.5	93.8	$ 644.1
Catarina	13.8	24.8	190.0	70.3	500.6
Maverick	9.6	0.2	1.2	10.0	185.3
Palmetto	0.4	0.1	0.9	0.8	11.0
Total Eagle Ford	53.4	57.2	384.6	174.9	1,341.0
TMS	0.3	—	—	0.3	4.5
Other Assets	0.7	0.1	0.4	0.8	9.5
Total	54.4	57.3	385.0	176.0	$ 1,355.0
Estimated proved undeveloped reserves by project area:					
Eagle Ford					
Comanche EF[5]	24.1	17.4	104.1	58.8	$ 147.4
Catarina	37.8	36.4	279.0	120.7	351.3
Maverick	3.2	—	—	3.2	7.5
Palmetto	2.9	0.6	3.5	4.0	24.9
Total Eagle Ford	68.0	54.4	386.6	186.7	531.1
TMS	—	—	—	—	—
Other Assets	—	—	—	—	—
Total	68.0	54.4	386.6	186.7	$ 531.1

(1) Our estimated net proved reserves and related standardized measure were determined using index prices for oil and natural gas, without giving effect to commodity derivative contracts, held constant throughout the life of our properties. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were \$51.34/Bbl for WTI Cushing oil, \$31.82/Bbl for NGLs and \$2.98/MMBtu for Henry Hub natural gas at December 31, 2017. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price realized at the wellhead. For the year ended December 31, 2017, the average realized prices for oil, NGLs and natural gas were \$48.69 per Bbl, \$20.52 per Bbl and \$3.10 per Mcf, respectively. For a description of our commodity derivative contracts, please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Operating Costs and Expenses—Commodity Derivative Transactions" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Derivative Instruments."

(2) One Boe is equal to six Mcf of natural gas or one Bbl of oil or NGLs based on an approximate energy equivalency. This is a physical correlation and does not reflect a value or price relationship between the commodities.

(3) PV-10 is a non-GAAP financial measure. See "Item 6. Selected Financial Data – Non-GAAP Financial Measures" for a reconciliation of PV-10 to Standardized Measure.

(4) Standardized measure is calculated in accordance with Accounting Standards Codification ("ASC"), Topic 932, Extractive Activities—Oil and Gas. For further information regarding the calculation of the standardized measure, see "Supplementary Information on Oil and Natural Gas Exploration, Development and Production Activities (Unaudited)" included in "Item 8. Financial Statements and Supplementary Data."

(5) SN Comanche Assets excluding approximately 16,100 net acres of deep rights only, which includes the Pearsall Shale.

The data in the table above represents estimates only. Oil, NGLs and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil, NGLs and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil, NGLs and natural gas that are ultimately recovered. For a discussion of risks associated with reserve estimates, please read "Item 1A. Risk Factors—Our estimated reserves and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves."

Future prices realized for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The standardized measure amounts shown above should not be construed as the current market value of our estimated oil and natural gas reserves. The 10% discount factor used to calculate standardized measure, which is required by Financial Accounting Standard Board ("FASB") pronouncements, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

Development of Proved Undeveloped Reserves

None of our proved undeveloped reserves ("PUD") at December 31, 2017 are scheduled to be developed on a date more than five years from the date the reserves were initially booked as proved undeveloped. Historically, our drilling and development programs were substantially funded from capital contributions, cash flow from operations and the issuance of debt and equity securities. Based on our current expectations of our cash flows and drilling and development programs, which includes drilling of proved undeveloped locations, we believe that we can fund the drilling of our current inventory of proved undeveloped locations and our expansions and extensions in the next five years from our cash on hand combined with cash flow from operations and utilization of available borrowing capacity under our amended and restated credit facility.

At a pace of approximately 30 wells per rig per year, our current 748 PUD drilling locations will all be developed within the next five years by running an average gross rig count of five rigs. As of December 31, 2017, we were running six active rigs and have an approved annual budget that allows for approximately six rigs to be run through 2018. For a more detailed discussion of our liquidity position, please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

As of December 31, 2017, we identified 748 gross (377 net) PUD drilling locations which we anticipate drilling within the next five years. The table below details the activity in our PUD locations from December 31, 2016 to December 31, 2017:

	Net Oil (MBbl)	Net Natural Gas Liquids (MBbl)	Net Natural Gas (MMcf)	Net Volume (MBoe)
PUDs as of December 31, 2016	46,332	37,606	268,136	128,627
Revisions of previous estimates				
Revisions due to price change	1,990	1,871	14,316	6,247
Technical revisions	(1,762)	(2,877)	(3,780)	(5,269)
Extensions and discoveries	10,461	6,953	48,790	25,546
Purchases	20,767	14,834	88,773	50,397
Divestitures	—	—	—	—
Conversion to proved developed reserves during the year	(9,891)	(4,007)	(29,632)	(18,837)
PUDs as of December 31, 2017	67,897	54,380	386,603	186,711

Excluding acquisitions, we expect to make capital expenditures related to drilling and completion of wells of approximately $420 million to $470 million during the year ended December 31, 2018. We plan to spend approximately 25% to 28% of these capital expenditures on development of PUDs in 2018. Technical revisions of PUD estimates are the result of changes in forecasted performance. Purchases are related to the 318,000 gross acres acquired as part of the Comanche Acquisition.

For more information about our historical costs associated with the development of proved undeveloped reserves, please read "Supplementary Information on Oil and Natural Gas Exploration, Development and Production Activities (Unaudited)" included in "Item 8. Financial Statements and Supplementary Data."

Production, Revenues and Price History

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

	Year Ended December 31,		
	2017	2016	2015
Production:			
Oil - MBbl			
Comanche	3,129	—	—
Catarina	3,180	3,615	3,210
Maverick	1,382	858	396
Cotulla	30	810	1,436
Palmetto	241	351	606
Marquis	222	693	1,448
TMS / Other	33	44	69
Total	8,217	6,371	7,165
Natural gas liquids - MBbl			
Comanche	3,025	—	—
Catarina	5,166	5,475	5,066
Maverick	48	14	5
Cotulla	1	237	326
Palmetto	55	78	139
Marquis	47	156	218
TMS / Other	—	—	—
Total	8,342	5,960	5,754
Natural gas - MMcf			
Comanche	17,615	—	—
Catarina	36,255	40,544	33,775
Maverick	281	93	42
Cotulla	(9)	1,393	2,075
Palmetto	305	494	774
Marquis	206	656	901
TMS / Other	(2)	9	27
Total	54,651	43,189	37,594
Net production volumes:			
Total oil equivalent (MBoe)	25,667	19,529	19,184
Average daily production (Boe/d)	70,320	53,358	52,560
Average Sales Price [(1)]:			
Oil ($ per Bbl)	$ 48.69	$ 37.95	$ 42.98
Natural gas liquids ($ per Bbl)	$ 20.52	$ 13.72	$ 11.99
Natural gas ($ per Mcf)	$ 3.10	$ 2.50	$ 2.63
Oil equivalent ($ per Boe)	$ 28.84	$ 22.09	$ 24.80
Average unit costs per Boe:			
Oil and natural gas production expenses	$ 9.52	$ 7.97	$ 8.06
Production and ad valorem taxes	$ 1.43	$ 1.01	$ 1.40
General and administrative expense	$ 5.63	$ 5.64	$ 3.87
Adjusted G&A per Boe [(2)(3)]	$ 3.55	$ 3.93	$ 2.90
Depreciation, depletion, amortization and accretion	$ 6.90	$ 7.55	$ 13.78
Impairment of oil and natural gas properties	$ 1.54	$ 2.43	$ 37.74

(1) Excludes the impact of derivative instruments.

(2) For the years ended December 31, 2017, 2016 and 2015, Adjusted general and administrative ("G&A") expense excludes non-cash stock-based compensation expense of approximately $22.9 million ($0.89 per Boe), $25.0 million ($1.28 per Boe) and $14.8 million ($0.77 per Boe), respectively.

(3) For the years ended December 31, 2017, 2016 and 2015, Adjusted G&A expense excludes acquisition and divestiture costs included in G&A expense of $30.5 million ($1.19 per Boe), $8.4 million ($0.43 per Boe) and $3.8 million ($0.20 per Boe), respectively.

The table above in addition to other areas throughout this Annual Report on Form 10-K contains disclosures of G&A expenses excluding expenses related to non-cash stock-based compensation expense and certain costs related to acquisitions and divestitures, which is referred to as "Adjusted G&A." Adjusted G&A is a "non-GAAP financial measure," as defined in SEC rules. Please see "Item 6. Selected Financial Data -- Non-GAAP Financial Measures," for a reconciliation of G&A and G&A per Boe to Adjusted G&A and Adjusted G&A per Boe, respectively.

Drilling Activities

The following table sets forth information with respect to wells drilled and completed during the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value. At December 31, 2017, 32 gross (7 net) wells were in various stages of completion.

	Year Ended December 31,					
	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	233.0	123.9	67.0	64.0	128.0	108.0
Dry (1)	1.0	1.0	1.0	1.0	—	—
Exploratory wells:						
Productive	—	—	—	—	8.0	8.0
Dry	—	—	—	—	—	—
Total wells:						
Productive	233.0	123.9	67.0	64.0	136.0	116.0
Dry (1)	1.0	1.0	1.0	1.0	—	—

(1) The Company encountered mechanical malfunctions during drilling and was unable to complete the well.

The following table sets forth information at December 31, 2017 relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we own an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated by us	392.0	162.9	1,672.0	687.0	2,064.0	849.9
Non-operated	100.0	11.3	1.0	0.3	101.0	11.6
Total	492.0	174.2	1,673.0	687.3	2,165.0	861.5

Developed and Undeveloped Acreage

The following table sets forth our estimated gross and net developed and undeveloped acreage as of December 31, 2017. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary table.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Comanche EF (1)	105,146	25,482	145,924	35,364	251,070	60,846
Catarina	21,271	21,271	84,780	84,780	106,051	106,051
Maverick	5,491	5,282	109,311	105,178	114,802	110,460
Palmetto	4,490	2,200	11,060	5,419	15,550	7,619
Total Eagle Ford	136,398	54,235	351,075	230,741	487,473	284,976
Comanche - Pearsall	1,080	265	64,515	15,857	65,595	16,122
TMS	1,000	1,000	36,432	36,432	37,432	37,432
Other	7,570	4,755	—	—	7,570	4,755
Total	146,048	60,255	452,022	283,030	598,070	343,285

(1) SN Comanche Assets excluding 16,122 net acres of deep rights only, which includes the Pearsall Shale.

As of December 31, 2017, approximately 76% of our acreage was held by production and/or continuous operations. As of December 31, 2017, we have leases that were not held by production and/or continuous operations representing approximately 15.1 thousand net acres (all of which were in the Eagle Ford Shale) expiring in 2018, 7.9 thousand net acres (7.2 thousand of which were in the Eagle Ford Shale) expiring in 2019, and 58.3 thousand net acres (46.5 thousand of which were in the Eagle Ford Shale) expiring in 2020 and beyond. We anticipate that our current and future drilling plans along with selected lease extensions will address the majority of our leases expiring in the Eagle Ford Shale in 2018 and beyond. We have a continuous development obligation in our Catarina area that requires us to drill, but not complete, (i) 50 wells in each annual period commencing on July 1, 2014 and (ii) at least one well in any consecutive 120 day period in order to maintain rights to any future undeveloped acreage. In addition to these lease expirations, we also have a continuous drilling obligation in our Comanche area, in addition to other requirements in the leases that must be adhered to in order to maintain our acreage position, that requires us to complete and equip 60 wells in each annual period that commenced on September 1, 2017.

Delivery Commitments

As is common in our industry, we have made commitments to certain purchasers to deliver a portion of our production from our Catarina area and our Comanche area.

Catarina Area

As of December 31, 2017, in our Catarina area, we have three contracts that require us to deliver portions of our natural gas, with delivery requirements through 2020, 2021 and 2022, respectively. Under the Gathering Agreement expiring in 2020, we are required to deliver 118 Bcf of natural gas through the Catarina Midstream gathering facilities. Under our contract expiring in 2021, we are required to deliver approximately 63 Bcf of natural gas. Under our contract expiring in 2022, we are required to deliver approximately 201 Bcf of natural gas. During 2017, we recorded expenses related to deficiencies on delivery commitments of approximately $0.2 million. These amounts were recorded to the “Oil and natural gas production expenses” line item in our consolidated statement of operations and were not considered material to the financial statement line item or to the consolidated financial statements as a whole. We expect to have additional expenses in 2018 related to deficiencies on our natural gas delivery commitments.

The Gathering Agreement also requires us to deliver a portion of our oil production through the Catarina Midstream gathering facilities. Under this contract, which expires in 2020, we are required to deliver approximately 8 MMBbls of oil. We do not expect to have additional expenses in 2018 related to deficiencies on our oil delivery commitments.

Comanche Area

We, as the operator, on behalf of ourselves and the other working interest partners, are party to two gathering agreements that require us to deliver variable monthly quantities through 2034. Gross volumes under these contracts peak at approximately 63,000 Bbl per day (approximately 14,800 Bbl per day net) of crude oil and condensate in 2020 and 430,000 Mcf per day (approximately 101,400 Mcf per day net) of natural gas in 2022, and then decrease annually thereafter through the end of the contracts. We are currently meeting our minimum volume commitments under these contracts and expect to continue to fulfill these obligations based on the applicable anticipated development plan. We do not expect to have additional expenses in 2018 related to deficiencies on these commitments.

We, as the operator, on behalf of ourselves and the other working interest partners, are party to three contracts that require us to deliver portions of our natural gas, with delivery requirements through 2021, 2023, and 2033, respectively. Under the contract expiring in 2021, we are required to deliver approximately 24 Bcf of natural gas. Under the contract expiring in 2023, we are required to deliver approximately 147 Bcf of natural gas. Under the contract expiring in 2033, we are required to deliver approximately 287 Bcf of natural gas. During 2017, we recorded expenses related to deficiencies on delivery commitments of approximately $1.8 million. We expect to have additional expenses in 2018 related to deficiencies on our natural gas delivery commitments.

We, as the operator, on behalf of ourselves and the other working interest partners, are party to one contract that require us to deliver portions of our NGLs. This contract expires in 2023 and requires us to deliver approximately 15 MMBbls of NGLs. During 2017, we recorded expenses related to deficiencies on delivery commitments of approximately $0.1 million. We do not expect to have additional expenses in 2018 related to deficiencies on our natural gas delivery commitments.

We, as the operator, on behalf of ourselves and the other working interest partners, are party to one contract that require us to deliver portions of our oil. This contract expires in 2020 and requires us to deliver approximately 5 MMBbls of oil. During 2017, we recorded expenses related to deficiencies on delivery commitments of approximately $2.7 million. We expect to have additional expenses in 2018 related to deficiencies on our oil delivery commitments.

Operations

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any well drilled on the lease premises. The lessor royalties and other leasehold burdens on our Eagle Ford properties range from 16.7% to 27.2%, resulting in a net revenue interest to us ranging from 72.8% to 83.3%.

Marketing and Major Customers

For the year ended December 31, 2017, purchases by four of our customers accounted for more than 10% (19%, 14%, 26%, and 23%, respectively) of our total revenues. The four customers, who are not affiliates of the Company, purchased oil, natural gas and NGLs from us pursuant to existing marketing agreements with terms that are currently on "evergreen" status and renew on a month-to-month basis until either party gives 30-day advance written notice of non-renewal.

Since the oil, natural gas and NGLs that we sell are commodities for which there are a large number of potential buyers and because of the adequacy of the infrastructure to transport these products in the areas in which we operate, if we were to lose one or more customers, we believe that we could readily procure substitute or additional customers such that our production volumes would not be materially affected for any significant period of time.

Hedging Activities

We enter into commodity derivative contracts with unaffiliated third parties to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in oil and natural gas prices. For a more detailed discussion of our hedging activities, please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Operating Costs and Expenses—Commodity Derivative Transactions," "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Derivative Instruments" and "Item 7A. Quantitative and Qualitative Disclosures about Market Risk."

Competition

We operate in a highly competitive environment for leasing and acquiring properties and in securing trained personnel. Our competitors specifically include major and independent oil and natural gas companies that operate in our project areas. These competitors include, but are not limited to, Carrizo Oil & Gas, Inc., Chesapeake Energy Corporation, EOG Resources, Inc., Marathon Oil Corporation, SM Energy Company and Noble Energy, Inc. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. As a result, our competitors may be able to pay more for productive oil and natural gas properties and exploratory prospects, as well as evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional properties and to find and develop reserves will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, there is substantial competition for capital available for investment in the oil and natural gas industry.

We are also affected by the competition for and the availability of equipment, including drilling rigs, completion equipment and materials. We are unable to predict when, or if, shortages of such equipment may occur or how they would affect our development and exploitation programs.

Title to Properties

Prior to completing an acquisition of producing oil and natural gas properties, we perform title reviews on significant leases, and depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. As a result, title examinations have been obtained on a significant portion of our properties. After an acquisition, we review the assignments from the seller for scrivener's and other errors and execute and record corrective assignments as necessary.

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the titles to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property.

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this Annual Report on Form 10-K.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months, resulting in seasonal fluctuations in the price we receive for our natural gas production. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations.

Environmental Matters and Regulation

General

Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment or otherwise relating to protection of the environment or occupational health and safety. Numerous governmental agencies, such as the Environmental Protection Agency (the “EPA”) and the Texas Railroad Commission (“Commission”), issue regulations, which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for failure to comply. These laws and regulations may, among other things (i) require the acquisition of permits to conduct exploration, drilling and production operations; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling, production and transportation activities; (iii) govern the sourcing and disposal of water used in the drilling and completion process; (iv) limit or prohibit drilling or injection activities on certain lands lying within wilderness, wetlands, seismically active areas, and other protected areas; (v) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; (vi) result in the suspension or revocation of necessary permits, licenses and authorizations; (vii) impose substantial liabilities for pollution resulting from drilling and production operations; and (viii) require that additional pollution controls be installed. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of corrective or remedial obligations, and the issuance of orders enjoining performance of some or all of our operations. Furthermore, liability under such laws and regulations is often strict (i.e., no showing of “fault” is required) and can be joint and several.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, the U.S. Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The historic trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment. Any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage transport, disposal, or remediation requirements could have a material adverse effect on our financial position and results of operations. Moreover, accidental releases or spills may occur in the course of our operations, and we could incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. While we believe that we are in substantial compliance with existing laws and regulations and that continued compliance with existing requirements will not materially affect us, there is no assurance that this situation will continue in the future.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Waste Handling

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict and, in some cases, joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, or CERCLA, also known as the Superfund law, and comparable state laws impose liability, without regard to fault or legality of conduct, on classes of persons considered to be responsible for the release, deemed "responsible parties," of a "hazardous substance" into the environment. These persons include the current owner or operator of the site where the release occurred, past owners or operators at the time a hazardous substance was released at the site, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons are subject to strict liability that, in some circumstances, may be joint and several for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file common law-based claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances, and despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. In addition, we may have liability for releases of hazardous substances at our properties by prior owners or operators or other third parties.

The Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state statutes and their implementing regulations, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Federal and state regulatory agencies can seek to impose administrative, civil and criminal penalties for alleged non-compliance with RCRA and analogous state requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil or natural gas, if properly handled, are exempt from regulation as hazardous waste under Subtitle C of RCRA. These wastes, instead, are regulated under RCRA's less stringent solid waste provisions, state laws or other federal laws. It is possible, however, that certain oil and natural gas exploration, development and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future and therefore be subject to more rigorous and costly disposal requirements. Indeed, legislation has been proposed from time to time in the U.S. Congress to re-categorize certain oil and natural gas exploration and production wastes as "hazardous wastes." Also, in December 2016, the EPA agreed in a consent decree to review its regulations of oil and gas waste. It has until March 2019 to determine whether any revisions are necessary. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration, production and processing for many years. Although we believe that we are in substantial compliance with the requirements of CERCLA, RCRA, and related state and local laws and regulations, that we hold all necessary and up-to-date permits, registrations and other authorizations required under such laws and regulations and that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination.

Water and Other Water Discharges and Spills

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act, the Safe Drinking Water Act, or the SDWA, the Oil Pollution Act of 1990, or the OPA, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including oil, produced waters and other hazardous substances, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or an analogous state agency. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers ("Corps"). On June 29, 2015, the EPA and the Corps jointly promulgated final rules redefining the scope of waters protected under the Clean Water Act. To the extent the rule expands the range of properties subject to the Clean Water Act's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. Following its promulgation, numerous states and industry groups challenged the rule and on October 9, 2015, a federal court stayed the rule's implementation nationwide, pending further action in court. In response to this decision, the EPA and the Corps have resumed nationwide use of the agencies' prior regulations defining the term "waters of the United States." Further, on February 28, 2017, President Trump signed an executive order directing the relevant executive agencies to review the rules and to initiate rulemaking to rescind or revise them, as appropriate under the stated policies of protecting navigable waters from pollution while promoting economic growth, reducing uncertainty, and showing due regard for Congress and the states. On July 27, 2017, the EPA and the Corps published a proposed rule to rescind the 2015 rules and, on February 6, 2018, the agencies published a final rule to maintain the status quo pending the agencies review of the 2015 rules. Further legal challenges are expected.

The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The underground injection of fluids is subject to permitting and other requirements under state laws and regulation.

Furthermore, the EPA is examining regulatory requirements for "indirect dischargers" of wastewater – i.e., those that send their discharges to private or publicly owned treatment facilities, which treat the wastewater before discharging it to regulated waters. On June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities.

Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Obtaining permits also has the potential to delay the development of oil and natural gas projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development, and require us to incur compliance costs.

The OPA amends the Clean Water Act and establishes strict liability and natural resource damages liability for unauthorized discharges of oil into waters of the United States. The OPA is the primary federal law imposing oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict liability that, in some circumstances, may be joint and several for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and the underground injection of fluids and are required to develop and implement spill prevention, control and countermeasure plans in connection with on-site storage of significant quantities of oil. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. We maintain all required discharge permits necessary to conduct our operations, and we believe we are in substantial compliance with their terms.

Regulation of Hydraulic Fracturing

Hydraulic fracturing is an important and common process used by oil and natural gas exploration and production operators in the completion of certain oil and natural gas wells whereby water, sand and chemicals are injected under pressure into subsurface formations to stimulate production of oil and/or natural gas. The SDWA regulates the underground injection of substances through the Underground Injection Control, or UIC, Program. Hydraulic fracturing is generally exempt from regulation under the UIC Program, and thus the hydraulic fracturing process is typically regulated by state oil and natural gas commissions. The EPA, however, has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the UIC Program. On February 12, 2014, the EPA published a revised UIC Program guidance for oil and natural gas hydraulic fracturing activities using diesel fuel. The guidance document describes how regulations of Class II wells, which are those wells injecting fluids associated with oil and natural gas production activities, may be tailored to address the purported unique risks of diesel fuel injection during the hydraulic fracturing process. Although the EPA is not the permitting authority for UIC Class II programs in Texas, Mississippi, and Louisiana, where we maintain acreage, the EPA is encouraging state programs to review and consider use of the above-mentioned guidance. In addition, the EPA previously announced its plans to develop a Notice of Proposed Rulemaking by June 2018, which would describe a proposed mechanism - regulatory, voluntary, or a combination of both - to collect data on hydraulic fracturing chemical substances and mixtures. Furthermore, legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, have been proposed in recent sessions of the U.S. Congress.

The protection of groundwater quality is extremely important to us. We believe that we follow all state and federal regulations and apply industry standard practices for groundwater protection in our operations. These measures are subject to close supervision by state and federal regulators. Our policy and practice is to follow all applicable guidelines and regulations in the areas where we conduct hydraulic fracturing. Accordingly, we set surface casing strings below the deepest usable quality fresh water zones and cement them back to the surface in accordance with applicable regulations, potential lease requirements and other legal requirements to ensure protection of existing fresh water zones. Also, prior to commencing drilling operations for the production portion of the hole, the surface casing strings are pressure tested to ensure mechanical integrity.

Although not presently relevant to our current 2017 development plans, on March 26, 2015, the Bureau of Land Management ("BLM") published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing, implementation of a casing and cementing program, management of recovered fluids, and submission to BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, and the depths of all usable water. On June 21, 2016, the United States District Court for Wyoming set aside the rule, holding that the BLM lacked Congressional authority to promulgate the rule. The BLM has appealed to the Tenth Circuit Court of Appeals. On March 28, 2017, President Trump signed an executive order directing the BLM to review the rule and, if appropriate, to initiate a rulemaking to rescind or revise it. Accordingly, on December 29, 2017, the BLM published a final rule to rescind the 2015 hydraulic fracturing rule. This decision has been challenged by state and environmental groups. At this time, it is uncertain when, or if, the rule will be implemented.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, on December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing to impact drinking water resources finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, have evaluated or are evaluating various other aspects of hydraulic fracturing.

These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing or the disposal of produced water and flowback fluid in underground injection wells under the SDWA or other regulatory mechanism.

Also, some states have adopted, and other states are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, in December 2011, the Commission adopted rules and regulations requiring that oil and gas operators publicly disclose the chemicals used in the hydraulic fracturing process. Also, in May 2013, the Commission adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. The new rules took effect in January 2014. Additionally, on October 28, 2014, the Commission adopted disposal well rule amendments designed, amongst other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed, new disposal well. The disposal well rule amendments, which became effective on November 17, 2014, also clarify the Commission's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The Commission has used this authority to deny permits for waste disposal sites.

A number of lawsuits and enforcement actions have been initiated across the country alleging that hydraulic fracturing practices have induced seismic activity and adversely impacted drinking water supplies, use of surface water, and the environment generally. Several states and municipalities have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances. These or any other new laws or regulations that significantly restrict hydraulic fracturing or the disposal of produced water and flowback fluid in underground injection wells could make it more difficult or costly for us to drill and produce from conventional and tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings.

Further federal, state and/or local laws governing hydraulic fracturing could result in additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such changes could cause us to incur substantial compliance costs, and compliance or the consequences of failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if additional federal or state and/or local laws are enacted.

Air Emissions

The federal Clean Air Act, as amended, and comparable state laws, regulate emissions of various air pollutants through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. On August 16, 2012, the EPA published final rules that subject oil and natural gas production, processing, transmission, and storage operations to regulation under the New Source Performance Standards (“NSPS”) and National Emission Standards for Hazardous Air Pollutants (“NESHAP”) programs. The rules include NSPS for completions of hydraulically fractured gas wells and establish specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rules seek to achieve a 95% reduction in Volatile Organic Compounds (“VOCs”) emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration. In particular, on May 12, 2016, the EPA amended its regulations to impose new standards for methane and VOC emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector. However, in a March 28, 2017 executive order, President Trump directed the EPA to review the 2016 regulations and, if appropriate, to initiate a rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation's energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. On June 16, 2017, the EPA published a proposed rule to stay for two years certain requirements of the 2016 regulations, including fugitive emission requirements.

Also, on November 15, 2016, the BLM finalized a rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The rule requires operators to use currently available technologies and equipment to reduce flaring, periodically inspect their operations for leaks, and replace outdated equipment that vents large quantities of gas into the air. The rule also clarifies when operators owe the government royalties for flared gas. State and industry groups have challenged this rule in federal court, asserting that the BLM lacks authority to prescribe air quality regulations. On March 28, 2017, President Trump signed an executive order directing the BLM to review the above rule and, if appropriate, to initiate a rulemaking to rescind or revise it. Accordingly, on December 8, 2017, the BLM published a final rule to suspend or delay certain requirements of the 2016 methane rule until January 17, 2019. Further legal challenges are expected. At this time, it is uncertain when, or if, the rule will be implemented.

These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. The need to obtain permits has the potential to delay the development of oil and natural gas projects, and our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. While we may be required to incur certain capital expenditures in the next few years for air pollution control equipment or other air emissions-related issues, we do not believe that such requirements will have a material adverse effect on our operations.

Climate Change

In recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases, or GHGs. The EPA has finalized a series of GHG monitoring, reporting and emission control rules for the oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of the states have already taken measures to reduce emissions of GHGs primarily through the development of GHG emission inventories and/or regional GHG cap-and-trade programs.

Furthermore, in December 2015, the United States participated in the 21st Conference of the Parties (COP-21) of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature, and to conserve and enhance sinks and reservoirs of GHGs. The Agreement went into effect on November 4, 2016 and establishes a framework for the parties to cooperate and report actions to reduce GHG emissions. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

Restrictions on GHG emissions that may be imposed could adversely affect the oil and natural gas industry. The adoption of any legislation or regulations that otherwise limit emissions of GHGs from our equipment and operations, could require us to incur increased operating costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with our operations, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby adversely affect demand for the oil and natural gas that we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations.

In addition, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Furthermore, claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury or property damages, or other liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Moreover, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornados and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially hotter or colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

National Environmental Policy Act

Oil and natural gas exploration, development and production activities on federal lands are subject to the National Environmental Policy Act, as amended, or NEPA. NEPA requires federal agencies, including the U.S. Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment to evaluate the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Currently, we have minimal exploration and production activities on federal lands. However, to the extent our current or future activities on federal lands are subject to the requirements of NEPA, this process has the potential to delay the receipt of governmental permits and the development of oil and natural gas projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Endangered Species Act

The Federal Endangered Species Act, or the ESA, and analogous state statutes restrict activities that may adversely threatened or endangered species or their habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act, though, in December 2017, the U.S. Fish and Wildlife Service provided guidance limiting the reach of the Act. Federal agencies are required to ensure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitat. While some of our facilities on federal lands may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. The U.S. Fish and Wildlife Service may identify, however, previously unidentified endangered or threatened species or may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species, which could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Occupational Safety and Health Act

We are also subject to the requirements of the Occupational Safety and Health Act, or OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Additionally, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the oil and natural gas industry with similar types, quantities and locations of production.

Drilling and Production

Our operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the disclosure of the chemicals used in the hydraulic fracturing process;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

Natural Gas Regulation

The availability, terms and cost of transportation significantly affect sales of natural gas. The interstate transportation and sale for resale of natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission, or FERC. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. FERC's regulations for interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas.

The FERC also possesses regulatory oversight over natural gas markets, including the purchase, sale and transportation activities of non-interstate pipelines and other natural gas market participants. FERC possesses substantial enforcement authority for violations of the Natural Gas Act (“NGA”), including the ability to assess civil penalties, order disgorgement of profits and recommend criminal penalties. The Energy Policy Act of 2005 amended the NGA to grant FERC new authority to facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce, and to prohibit market manipulation. FERC's anti-manipulation regulations apply to FERC jurisdictional activities, which have been broadly construed by the FERC. Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial civil and criminal penalties, including civil penalties of up to $1.0 million per day, per violation.

In 2008, FERC took additional steps to enhance its market oversight and monitoring of the natural gas industry. Order No. 704, as clarified in orders on rehearing, requires buyers and sellers of natural gas above a de minimis level, including entities not otherwise subject to FERC jurisdiction, to submit an annual report to FERC describing their wholesale physical natural gas transactions that use an index or that contribute to or may contribute to the formation of a gas index. The FERC also contemplated expanding the industry's reporting requirements. On November 15, 2012, the FERC issued a Notice of Inquiry seeking comments whether requiring quarterly reporting of every gas transaction within the FERC's jurisdiction that entails physical delivery for the next day or the next month would provide useful information for improving natural gas market transparency. The FERC ultimately determined that imposing a quarterly reporting requirement is not necessary at this time and exercised its discretion to terminate the Notice of Inquiry on November 17, 2015.

Although natural gas prices are currently unregulated, the U.S. Congress historically has been active in the area of natural gas regulation. We cannot predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by the U.S. Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of our properties. Sales of condensate and NGLs are not currently regulated and are made at market prices.

State Regulation

The various states regulate the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. For example, Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources. States may regulate rates of production and may establish maximum daily production from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amount of natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

The oil and natural gas industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Employees

We currently do not have any employees. Pursuant to our Services Agreement, SOG performs services for us, including the operation of our properties. Please also read “Item 8. Financial Statements and Supplementary Data — Note 10, Related Party Transactions.” As of December 31, 2017, SOG had approximately 312 employees, including 37 engineers, 16 geoscientists and 14 land professionals. None of these employees are represented by labor unions or covered by any collective bargaining agreement. We believe that SOG’s relations with its employees are satisfactory.

We also contract for the services of independent consultants involved in land, engineering, regulatory, accounting, financial and other disciplines as needed.

Offices

For our principal offices, we currently share offices with other members of the Sanchez Group under leases entered into by the Company covering approximately 90,000 square feet of office space in Houston, Texas at 1000 Main Street, Suite 3000, Houston, Texas 77002, expiring in 2025. In addition, SOG maintains offices in San Antonio, Texas.

Available Information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any documents filed by us with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Our filings with the SEC are also available to the public from commercial document retrieval services and at the SEC's website at http://www.sec.gov.

Our common stock is listed and traded on the New York Stock Exchange ("NYSE") under the symbol "SN." Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

We also make available on our website at http://www.sanchezenergycorp.com all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Information contained on our website is not incorporated by reference into this Annual Report on Form 10-K.

Item 1A. *Risk Factors*

Our business involves a high degree of risk. You should consider and read carefully all of the risks and uncertainties described below, together with all of the other information contained in this Annual Report on Form 10-K, including the financial statements and the related notes appearing at the end of this Annual Report on Form 10-K. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, were to occur, our business, financial condition or results of operations could be adversely affected. The risks below are not the only ones facing the Company. Additional risks not currently known to us or that we currently deem immaterial may also adversely affect us. This Annual Report on Form 10-K also contains forward-looking statements, estimates and projections that involve risks and uncertainties. Our actual results could differ materially from those anticipated in the forward-looking statements as a result of specific factors, including the risks described below. Also, please read "Cautionary Note Regarding Forward-Looking Statements."

Risks Related to Our Business

Market conditions for oil, natural gas and NGLs are highly volatile. A sustained decline in prices for these commodities could adversely affect our revenue, cash flows, profitability and growth.

Prices for oil, natural gas and NGLs fluctuate widely in response to a variety of factors that are beyond our control, such as:

- domestic and foreign supply of and demand for oil, natural gas and NGLs;
- weather conditions and the occurrence of natural disasters;
- overall domestic and global economic conditions;
- political and economic conditions in countries producing oil, natural gas and NGLs, including terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war;
- actions of OPEC and other state-controlled oil companies relating to oil price and production controls;

- the effect of increasing liquefied natural gas and exports from the United States;

- the impact of the U.S. dollar exchange rates on prices for oil, natural gas and NGLs;

- technological advances affecting energy supply and energy consumption;

- domestic and foreign governmental regulations, including regulations prohibiting or restricting our ability to apply hydraulic fracturing to our wells, and taxation;

- the impact of energy conservation efforts and alternative fuel requirements;

- the proximity, capacity, cost and availability of production and transportation facilities for oil, natural gas and NGLs;

- the availability of refining capacity; and

- the price and availability of, and consumer demand for, alternative fuels.

Governmental actions may also affect prices for oil, natural gas and NGLs. In the past, prices for oil, natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. Beginning in the latter half of 2014, oil prices declined precipitously, and continued to decline throughout 2015 as well as the start 2016. Such downward volatility has negatively affected the amount of our net estimated proved reserves and has negatively affected the standardized measure of discounted future net cash flows of our net estimated proved reserves. Although we did not record a proved property impairment during the year ended December 31, 2017, we recorded proved property impairment of $3.7 million and $700.3 million for the years ended December 31, 2016 and December 31, 2015, respectively.

In addition, our revenue, profitability and cash flow depend upon the prices of and demand for oil, natural gas and NGLs, and continued price volatility and low commodity prices, or a sustained drop in prices could negatively affect our financial results and impede our growth. In particular, sustained declines in commodity prices will:

- limit our ability to enter into commodity derivative contracts at attractive prices;

- reduce the value and quantities of our reserves, because declines in prices for oil, natural gas and NGLs would reduce the amount of oil, natural gas and NGLs that we can economically produce;

- reduce the amount of cash flow available for capital expenditures;

- limit our ability to borrow money or raise additional capital; and

- make it uneconomical for our operating partners to commence or continue production levels of oil, natural gas and NGLs.

An increase in the differential between the NYMEX or other benchmark prices of oil, natural gas and NGLs and the wellhead price we receive for our production could adversely affect our business, financial condition and results of operations.

The prices that we receive for the oil, natural gas and NGLs that we produce at times may reflect differences between the relevant benchmark prices, such as NYMEX, that are used for calculating hedge positions. The difference between the benchmark price and the price we receive is called a basis differential. Increases in the basis differential between the benchmark prices for oil, natural gas and NGLs and the wellhead price we receive could adversely affect our business, financial condition and results of operations. We do not have or currently plan to have any commodity derivative contracts covering the amount of the basis differentials we experience in respect of our production. As such, we will be exposed to any increase in such differentials, which could adversely affect our business, financial condition and results of operations.

As of February 23, 2018, we had commodity derivative contracts in place representing approximately 72% and 110% of the mid-point of our production of oil and natural gas projections, respectively, for 2018. In the future, we expect to continue to enter into commodity derivative contracts for a portion of our estimated production, which could result in net gains or losses on commodity derivatives. Our hedging strategy and future hedging transactions will be determined by our management in accordance with the terms of SN UnSub's organizational documents and any restrictions or limitations in our debt instruments.

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 under these contracts. Accordingly, our hedging strategy may not protect us from significant 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. As such, our hedging strategy may not protect us from changes in the price of oil, natural gas and NGLs, which could have a significant adverse effect on our liquidity, business, financial condition and results of operations.

Further declines in commodity prices or unsuccessful exploration efforts may result in write-downs of our asset carrying values.

During the fourth quarter of 2017, the Company changed its method of accounting for its oil and gas exploration and development activities from full cost to the successful efforts method of accounting. All property and acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending the determination of whether proved reserves have been discovered. If proved reserves are not discovered with an exploratory well, the costs of drilling the well are expensed. The capitalized costs of our oil and gas properties, on a field basis, cannot exceed the estimated future net cash flows of that field. If the net capitalized costs exceed future net revenues, we must write down the costs of each such field to our estimate of fair market value. Unproved properties are evaluated at the lower of cost or fair market value. Accordingly, a significant decline in oil or gas prices or unsuccessful exploration efforts could cause a future write-down of capitalized costs.

We review the carrying value of our proved oil and gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The impairment analysis is based on then current oil and gas prices in effect. Once incurred, a write-down of oil and gas properties cannot be reversed at a later date even if oil or gas prices increase. As a result, substantial and sustained declines in oil and natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

The Company's derivative risk management activities could result in financial losses.

To mitigate the effect of commodity price volatility on the Company's net cash provided by operating activities, support the Company's annual capital budgeting and expenditure plans and reduce commodity price risk associated with certain capital projects, our strategy is to enter into derivative contracts covering a portion the Company's production. These derivative arrangements are subject to mark-to-market accounting treatment, and the changes in fair market value of the contracts are reported in the Company's statements of operations each quarter, which may result in significant non-cash gains or losses. After the current hedges expire, there is significant uncertainty that we will be able to put new hedges in place that will provide us with the same benefit. These derivative contracts may also expose the Company to risk of financial loss in certain circumstances, including when:

- production is less than the contracted derivative volumes, in which case we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flow from our sale of the underlying physical commodity;

- the counterparty to the derivative contract defaults on its contractual obligations;

- there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge instrument; or

- the derivative contracts limit the benefit the Company would otherwise receive from increases in commodity prices.

Such financial losses could materially impact our liquidity, business, financial condition and results of operations.

The Comanche Acquisition or any other acquisition we may undertake involve risks associated with acquisitions and integration of acquired assets, and the intended benefits of the Comanche Acquisition or any other acquisition we may undertake may not be realized.

The Comanche Acquisition or any other acquisition we may undertake involve risks associated with acquisitions and integrating acquired assets into existing operations, including that:

- our senior management's attention may be diverted from the management of daily operations with respect to our Catarina area and our other legacy assets to the integration of the assets acquired in the Comanche Acquisition or other acquisition;

- we could incur significant unknown and contingent liabilities for which we have limited or no contractual remedies or insurance coverage;

- we may be unable to achieve the economies of scale that we expect from integrating the Comanche Assets or any other assets we may acquire into our existing operations;

- the assets acquired in the Comanche Acquisition or any other acquisition we may undertake may not perform as well as we anticipate; and

- unexpected costs, delays and challenges may arise in integrating the assets acquired in the Comanche Acquisition or any other acquisition we may undertake into our existing operations.

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

Under the terms of the lease with respect to the Catarina assets and under the terms of the Comanche development agreement, we are subject to annual drilling and development requirements and failure to comply with these requirements may result in loss of our interests in the Catarina area that are not held by production or sizable default payments to Anadarko, respectively.

In order to protect our exploration and development rights in the Catarina area, we are required to drill 50 wells per year (measured from July 1 to June 30). If we fail to meet the minimum drilling commitment under the terms of the lease for our Catarina properties (the "Catarina Lease"), we could forfeit our acreage under the Catarina Lease and rights to develop land not held by production (excluding, in certain instances, associated rights such as midstream assets). If we drill more than 50 wells in a prescribed twelve month period, we may apply such additional wells (up to a maximum of 30 additional wells) toward the following prescribed twelve month period's 50-well requirements. In addition, the Catarina Lease requires us to go no longer than 120 days without spudding a well, and, under the terms of the Catarina Lease, failure to do so could result in the forfeiture of our acreage under the Catarina Lease and rights to develop land not held by production (excluding, in certain instances, acreage upon which associated midstream assets are located).

We also entered into a development agreement (the “Development Agreement”) with Anadarko regarding the Comanche Assets pursuant to which we commit to completing and equipping 60 wells per year for 5 years, in addition to other requirements in the leases that must be adhered to in order to maintain our acreage position. If we complete and equip more than 60 wells in a year, we may apply such additional wells (up to a maximum of 30 additional wells) toward the 60-well requirement in subsequent annual periods. 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 must pay Anadarko a default fee of $200,000 for each well we fail to timely complete and equip.

Our drilling plans for our undeveloped leasehold acreage are subject to change based upon various factors, including factors that are beyond our control, such as drilling results, prices for oil, natural gas and NGLs, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. Because of these uncertainties, we cannot assure you that we will be able meet our obligations under the Catarina Lease or the Development Agreement. If the Catarina Lease expires, we will lose our right to develop the related properties on this acreage, which could adversely affect our business, financial condition and results of operations. If we fail to meet our obligations under the Development Agreement we will have to pay Anadarko the applicable default fees, which could adversely affect our business, financial condition and results of operations.

Our agreements with Blackstone and GSO Capital Partners LP (“GSO”) will restrict us from transferring our right, title and interest to the Comanche Assets.

Under the terms of the joint development agreement with Blackstone (the “JDA”), except under limited circumstances, neither we nor Blackstone can transfer any of our rights, title or interest to any asset or related assets (including any working interests) prior to the third anniversary of the JDA. In addition, under our agreements with GSO, we are not able to dispose of all or a substantial portion of the Comanche Assets without GSO’s consent. These restrictions may prohibit us from taking advantage of certain opportunities, including our ability to sell these assets, which may arise from time to time.

The JDA contains right of first offer (“ROFO”) and tag-along provisions that may hinder our ability to sell our interest in the Comanche Assets within our desired time frame or on our desired terms, and could delay or prevent an acquisition of us, even if the acquisition would be beneficial to our stockholders.

Under the terms of the JDA, both parties have a ROFO in the event that the other party intends to sell or otherwise transfer its interests. In addition, the JDA provides both parties with a tag-along right in the event that the other party intends to sell at least 35% of its total interests to a third-party purchaser (including upon a change of control transaction involving us). These features could limit third-party offers, inhibit our ability to sell our interests or adversely affect the timing of any sale of our interests and our ability to obtain the highest price possible in the event that we decide to market or sell our interests. In addition, the tag-along provisions of the JDA may also frustrate or prevent any attempts by our stockholders or a third party to replace or remove our current management or to acquire an interest in or engage in other corporate transactions with us, by subjecting certain corporate change of control transactions to a tag-along provision pursuant to which a third party may be required to acquire Blackstone’s interest in the Comanche Assets if it desires to enter into a corporate transaction with us.

The JDA establishes an operating committee for the Comanche Assets that keeps us from having unilateral control over many key variables of operation and development of the Comanche Assets and also provides for certain circumstances under which we could be removed as operator.

The JDA provides for the administration, operation and transfer of the jointly-owned Comanche Assets. Pursuant to the JDA, the parties thereto established an operating committee, which controls the timing, scope and budgeting of operations on the Comanche Assets (subject to certain exceptions). Although we are designated as operator of the Comanche Assets under the JDA, under certain circumstances we may be removed as operator and, furthermore, because we do not control the operating committee we do not have unilateral control over many key variables of the operation and development of the Comanche Assets, including the establishment of the budget and development plan for the Comanche Assets. There can be no assurance that Blackstone will continue its relationship with us in the future or that we will be able to pursue our stated strategies with respect to the Comanche Assets. Furthermore, Blackstone may (a) have economic or business interests or goals that are inconsistent with ours; (b) take actions contrary to our policies or objectives; (c) undergo a change of control; (d) experience financial and other difficulties; or (e) be unable or unwilling to fulfill their obligations under the JDA, which may affect our financial conditions or results of operations.

Under the amended and restated limited liability company agreement of SN UnSub and the limited liability company agreement of SN UnSub's general partner, GSO consent is required to take certain actions.

Under the amended and restated limited partnership agreement of SN UnSub and limited liability company agreement of SN UnSub's general partner, we are not able to cause SN UnSub or its general partner to take or not to take certain actions unless GSO consents. GSO made a substantial investment (including contributions and other commitments) in SN UnSub at the closing of the Comanche Acquisition and, accordingly, has required that the relevant organizational documents of SN UnSub and its general partner contain certain features designed to provide it with the opportunity to participate in the management of SN UnSub and its general partner and to protect its investment in SN UnSub, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of SN UnSub. These participation and protective features include a governance structure that consists of a board of directors of SN UnSub's general partner, only some of whom are appointed by us. Thus, without the concurrence of GSO, we will not be able to cause SN UnSub and its general partner to take or not to take certain actions, even though those actions may be in the best interest of SN UnSub, its general partner, or us. Furthermore, we, and GSO may have different or conflicting goals or interests which could make it more difficult or time-consuming to obtain any necessary approvals or consents to pursue activities that we believe to be in the best interests of our stockholders. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources."

Our estimated reserves and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves.

Numerous uncertainties are inherent in estimating reserves of oil, natural gas and NGLs and future production. It is not possible to measure underground accumulations of oil, natural gas and NGLs in an exact way. Reserve engineering is complex, requiring subjective estimates of underground accumulations of oil, natural gas and NGLs and assumptions concerning future prices for oil, natural gas and NGLs, future production levels and operating and development costs. In estimating our reserves of oil, natural gas and NGLs, we and our independent reserve engineers make certain assumptions that may prove to be incorrect, including assumptions relating to:

- prices for oil, natural gas and NGLs;
- future production levels;
- capital expenditures;
- operating and development costs;
- the effects of regulation;
- the accuracy and reliability of the underlying engineering and geologic data; and
- the availability of funds.

If these assumptions prove to be incorrect, our estimates of our reserves, the economically recoverable quantities of oil, natural gas and NGLs attributable to any particular group of properties, the classifications of reserves based on risk of recovery and our estimates of the future net cash flows from our estimated reserves could change significantly. For example, with other factors held constant, if the commodity prices used in our reserve report as of December 31, 2017 had decreased by 10%, then the standardized measure of our estimated proved reserves as of that date would have decreased by approximately $511.8 million, from approximately $1,886.1 million to approximately $1,374.3 million.

Our standardized measure is calculated using unhedged prices for oil, natural gas and NGLs and is determined in accordance with the rules and regulations of the SEC. Over time, we may make material changes to reserve estimates to take into account changes in our assumptions and the results of actual development and production.

The reserve estimates we make for wells or fields that do not have a lengthy production history are less reliable than estimates for wells or fields with lengthy production histories. A lack of production history may contribute to inaccuracy in our estimates of proved reserves, future production rates and the timing of development expenditures.

Our estimated reserves of oil, natural gas and NGLs will naturally decline over time, and we may be unable to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, financial condition and results of operations.

Our future reserves of oil, natural gas and NGLs, production volumes, and cash flow depend on our success in developing and exploiting our current reserves efficiently and finding or acquiring additional recoverable reserves economically. Our estimated reserves of oil, natural gas and NGLs will naturally decline over time as they are produced. Our success depends on our ability to economically develop, find or acquire additional reserves to replace our own current and future production. If we are unable to do so, or if expected development is delayed, reduced or cancelled, the average decline rates will likely increase.

Developing and producing oil, natural gas and NGLs are costly and high-risk activities with many uncertainties that could adversely affect our business, financial condition and results of operations.

The cost of developing, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Additionally, drilling wells with no or sub-economic levels of production (dry holes) will negatively impact our financial position. In addition, our use of 2D and 3D seismic data and visualization techniques to identify subsurface structures and hydrocarbon indicators do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures and requires additional pre-development expenditures. Furthermore, our development and production operations may be curtailed, delayed or canceled as a result of other factors, including:

- high costs, shortages or delivery delays of rigs, equipment, labor or other services;
- composition of sour gas, including sulfur and mercaptan content;
- unexpected operational events and conditions;
- reductions in prices for oil, natural gas and NGLs;
- increases in severance taxes;
- adverse weather conditions and natural disasters;
- facility or equipment malfunctions and equipment failures or accidents, including acceleration of deterioration of our facilities and equipment due to the highly corrosive nature of sour gas;
- title problems;
- pipe or cement failures, casing collapses or other downhole failures;
- compliance with ever-changing environmental and other governmental requirements;

- environmental hazards, such as chemical or hydrocarbon leaks or spills, salt water leaks or spills, pipeline ruptures, discharges of toxic gases or other releases of hazardous substances;
- lost or damaged oilfield development and service tools;
- unusual or unexpected geological formations and pressure or irregularities in formations;
- loss of drilling fluid circulation;
- fires, blowouts, surface craterings and explosions;
- uncontrollable flows of oil, natural gas, NGLs or well fluids;
- loss of leases due to incorrect payment of royalties;
- limited availability of financing at acceptable rates; and
- other hazards, including those associated with sour gas such as an accidental discharge of hydrogen sulfide gas, that could also result in personal injury and loss of life, pollution and suspension of operations.

If any of these factors were to occur with respect to a particular field, we could lose all or a part of our investment in the field, or we could fail to realize the expected benefits from the field, either of which could materially and adversely affect our business, financial condition and results of operations.

We routinely apply hydraulic fracturing techniques in many of our drilling and completion operations. Hydraulic fracturing has recently become subject to increased public scrutiny and recent changes in federal and state law, as well as proposed legislative changes, could significantly restrict the use of hydraulic fracturing. Such laws could make it more difficult or costly for us to perform fracturing to stimulate production from dense subsurface rock formations and, in the event of local prohibitions against commercial production of natural gas, may preclude our ability to drill wells. In addition, such laws could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. If hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA or other federal agencies, our fracturing activities could become subject to additional permitting requirements and result in permitting delays, financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements, as well as potential increases in costs. Please read "—Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays" and "Item 1. Business—Environmental Matters and Regulation—Water and Other Water Discharges and Spills."

Additionally, hydraulic fracturing, drilling, transportation and processing of hydrocarbons bear an inherent risk of loss of containment. Potential consequences include loss of reserves, loss of production, loss of economic value associated with the affected wellbore, contamination of soil, ground water, and surface water, as well as potential fines, penalties or damages associated with any of the foregoing consequences.

Our acquisition, development and production operations require us to make substantial capital expenditures. Although we expect to fund our capital expenditure budget for 2018 using cash flow from operations and cash on hand, if our cash flow from operations turns out to be less than we currently expect and we are required, but are unable, to fund our remaining capital budget from other sources, such as borrowings under our amended and restated credit facility and/or the issuance of debt or equity securities, our failure to obtain the funds that we need could have a material adverse effect on our business, financial condition and results of operations.

The oil and natural gas industry in which we operate is capital intensive and we must make substantial capital expenditures in our business for the acquisition, development and production of oil, natural gas and NGLs. Our cash on hand, cash flows from operations, ability to borrow and access to capital markets are subject to a number of variables, many of which are beyond our control, including:

- our estimated reserves of proved oil, natural gas and NGLs;
- the amount of oil, natural gas and NGLs we produce;
- the prices at which we sell our production;
- the results of our hedging strategy;
- the costs of developing, producing, and transporting our oil, natural gas and NGLs, including costs attributable to governmental regulation and taxation;
- our ability to acquire, locate and produce new reserves;
- fluctuations in our working capital needs;
- interest payments, debt service and dividend payment requirements;
- prevailing economic and capital markets conditions, especially for oil and gas companies;
- our financial condition; and
- the ability and willingness of banks and other lenders to lend to us.

In addition, we may be unable to access the capital markets for debt or equity financing. If we are unsuccessful in obtaining the funds we need to fund our capital budget, we will be forced to reduce our capital expenditures, which in turn could lead to a decline in our production, revenues and our reserves, and could adversely affect our business, financial condition and results of operations.

Our stock price has been volatile, and investors in our common stock could incur substantial losses.

During the year ended December 31, 2017, our stock price had a low closing price of $3.75 per share and a high closing price per share of $14.24 per share. As a result of this volatility, investors may not be able to sell their common stock at or above the price at which they purchased their shares. The market price for our common stock may be influenced by many factors, including, but not limited to:

- the price of oil, natural gas and NGLs;
- the success of our exploration and development operations, and the marketing of any oil we produce;
- regulatory developments in the United States;
- the recruitment or departure of key personnel;
- quarterly or annual variations in our financial results or those of companies that are perceived to be similar to us;
- market conditions in the industries in which we compete and issuance of new or changed securities;
- analyst reports or recommendations;
- the failure of securities analysts to cover our common stock or changes in financial estimates by analysts;

- higher than achievable estimates by analysts who follow our common stock;
- our issuance of any additional securities;
- investor perception of our company and of the industry in which we compete; and
- general economic, political and market conditions.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage or the leases are extended.

Certain of our undeveloped leasehold acreage is subject to leases that will expire unless production in paying quantities is established during their primary terms or we obtain extensions of the leases. Our drilling plans for our undeveloped leasehold acreage are subject to change based upon various factors, including factors that are beyond our control, such as drilling results, prices for oil, natural gas and NGLs, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. Because of these uncertainties, we do not know if our undeveloped leasehold acreage will ever be drilled or if we will be able to produce crude oil, natural gas or NGLs from these or any other potential drilling locations. If our leases expire and we do not have them held by production, we will lose our right to develop the related properties on this acreage.

As of December 31, 2017, approximately 76% of our acreage was held by production and/or continuous operations. As of December 31, 2017, we had leases that were not held by production representing 15.1 thousand net acres (all which were in the Eagle Ford Shale) expiring in 2018, 7.8 thousand net acres (7.2 thousand of which were in the Eagle Ford Shale) expiring in 2019, and 58.3 thousand net acres (46.5 thousand of which were in the Eagle Ford Shale) expiring in 2020 and beyond. While we anticipate that our current and future drilling plans will address the majority of our leases expiring in the Eagle Ford Shale in 2018, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business, financial condition and results of operation.

Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has specifically identified and scheduled drilling locations as an estimation of our future drilling activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, prices for oil, natural gas and NGLs, costs and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil, natural gas or NGLs from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business, financial condition and results of operations.

We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate revenue.

The oil and natural gas industry is intensely competitive with respect to acquiring prospects and properties, the marketing of oil, natural gas and NGLs, and securing equipment and trained personnel. Many of our competitors are large independent oil and natural gas companies that possess and employ financial, technical and personnel resources substantially greater than those of the Sanchez Group. Those entities may be able to develop and acquire more properties than our financial or personnel resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial, technical or personnel resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These larger companies may have a greater ability to continue development activities during periods of lower prices for oil, natural gas and NGLs and to absorb the burden of present and future federal, state, local and other laws and regulations. Furthermore, we may not be able to aggregate sufficient quantities of production to compete with larger companies that are able to sell greater volumes of production to intermediaries, thereby reducing the realized prices attributable to our production. Any inability to compete effectively with larger companies could have a material adverse impact on our business, financial condition and results of operations.

Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured.

There are a variety of operating risks inherent in our wells and other operating properties and facilities, such as leaks, explosions, mechanical problems and natural disasters, all of which could cause substantial financial losses. Any of these or other similar occurrences could result in the disruption of our operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial revenue losses. The location of our wells and other operating properties and facilities near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from these risks.

Insurance against all operational risks is not available to us. We are not fully insured against all risks, including development and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable costs or on commercially reasonable terms. Changes in the insurance markets due to weather, adverse economic conditions, and the aftermath of the Macondo well incident in the Gulf of Mexico have made it more difficult for us to obtain certain types of coverage. As a result, we may not be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes, and we cannot be sure the insurance coverage we do obtain will not contain large deductibles or fail to cover certain hazards or cover all potential losses. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our business, financial condition and results of operations.

Our lack of diversification increases the risk of an investment in us and we are vulnerable to risks associated with operating in one major contiguous area.

Our current business focus is on the oil and natural gas industry in a limited number of properties, in the Eagle Ford Shale in South Texas and, to a lesser extent, the TMS in Southwest Mississippi and Southeast Louisiana. Larger companies have the ability to manage their risk by diversification. However, we currently lack diversification, in terms of both the nature and geographic scope of our business. For example, our Catarina assets, comprised of approximately 106,000 contiguous net acres in Dimmit, LaSalle and Webb Counties, Texas under the Catarina Lease, represent approximately 53% of our proved reserves as of December 31, 2017, approximately 37% of our Eagle Ford acreage as of December 31, 2017 and approximately 56% of our total production volumes for the year ended December 31, 2017. As a result, we will likely be impacted more acutely by factors affecting our industry or the regions in which we operate than we would if our business were more diversified, increasing our risk profile. In particular, we may be disproportionately exposed to the impact of delays or interruptions of production from wells in which we have an interest that are caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of oil or natural gas produced from wells in the Eagle Ford Shale. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

We cannot control activities on properties that we do not operate and are unable to control their proper operation and profitability.

We do not operate all of the properties in which we own an ownership interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operations of these non-operated properties. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interests could reduce our production, revenues and reserves. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors outside of our control, including:

- the nature and timing of the operator's drilling and other activities;
- the timing and amount of required capital expenditures;
- the operator's geological and engineering expertise and financial resources;
- the approval of other participants in drilling wells; and
- the operator's selection of suitable technology.

Our ability to produce oil and natural gas could be impaired if we are unable to acquire adequate supplies of water for our drilling and completion operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules.

Water is an essential component of oil and natural gas production during both the drilling and hydraulic fracturing processes. Drought conditions have persisted in our areas of operation in past years. These drought conditions have led governmental authorities to restrict the use of water, subject to their jurisdiction, for hydraulic fracturing to protect local water supplies. If we are unable to obtain water to use in our operations, we may be unable to economically produce oil and natural gas, which could have a material and adverse effect on our financial condition, results of operations and cash flows.

Furthermore, the Clean Water Act imposes restrictions and strict controls regarding the discharge of produced waters and other oil and natural gas waste into navigable waters. In addition, the underground injection of fluids is subject to permitting and other requirements under state laws and regulation. Public concerns regarding the potential impacts to groundwater and induced seismic activity have resulted in new requirements related to the underground injection and disposal of fluids.   The EPA is also examining regulatory requirements for "indirect dischargers" of wastewater – i.e., those that send their discharges to private or publicly owned treatment facilities, which treat the wastewater before discharging it to regulated waters. Compliance with environmental regulations and permit requirements governing the discharge of underground injection of fluids and the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted.

We may lose our rights to the Sanchez Group's technological database, including its 3D and 2D seismic data, under certain circumstances.

Pursuant to the Services Agreement, we have access to the unrestricted, proprietary portions of the technological database owned and maintained by the Sanchez Group and related to our properties, and SOG is otherwise required to interpret and use the database, to the extent relating to our properties, for our benefit under the Services Agreement. For a description of the Services Agreement see "Item 8. Financial Statements and Supplementary Data — Note 10, Related Party Transactions" in the notes to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" of this Annual Report on Form 10-K. This database includes the 2D and 3D seismic data used for our exploration and development projects as well as the well logs, LAS files, scanned well documents and other well documents and software that are necessary for our daily operations. This information is critical for the operation and expansion of our business. Under certain circumstances, including if SOG provides at least

180 days' advance written notice of its desire to terminate the Services Agreement, the license agreement will terminate and we will lose our rights to this technological database unless members of the Sanchez Group permit us to retain some or all of these rights, which they may decline to do in their sole discretion. In such event, we are unlikely to be able to obtain rights to similar information under substantially similar commercial terms or to continue our business operations as proposed and our liquidity, business, financial condition and results of operations will be materially and adversely affected and it could delay or prevent an acquisition of us.

If we do not purchase additional acreage or make acquisitions on economically acceptable terms, our future growth will be limited.

Our ability to grow depends in part on our ability to make acquisitions on economically acceptable terms. We may be unable to make such acquisitions because we are:

- unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with their owners;
- unable to obtain financing for such acquisitions on economically acceptable terms; or
- outbid by competitors.

If we are unable to acquire properties containing estimated proved reserves, our total level of estimated proved reserves will decline as a result of our production.

Any acquisitions we complete or geographic expansions we undertake will be subject to substantial risks that could have a negative impact on our business, financial condition and results of operations.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about estimated proved reserves, future production, revenues, capital expenditures, operating expenses and costs, including synergies, timing of expected development and the potential for expiration of underlying leaseholds;
- an inability to successfully integrate the assets or businesses we acquire;
- a decrease in our liquidity by using a significant portion of our cash and cash equivalents to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which any indemnity we receive is inadequate;
- the diversion of management's attention from other business concerns;
- mistaken assumptions about the overall cost of equity or debt;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;
- facts and circumstances that could give rise to significant cash and certain non-cash charges; and
- customer or key employee losses at the acquired businesses.

Further, we may in the future expand our operations into new geographic areas with operating conditions and a regulatory environment that may not be as familiar to us as our existing project areas. As a result, we may encounter obstacles that may cause us not to achieve the expected results of any such acquisitions, and any adverse conditions, regulations or developments related to any assets acquired in new geographic areas may have a negative impact on our business, financial condition and results of operations.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic data and other information, the results of which are often inconclusive and subject to various interpretations. Our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition, given time constraints imposed by sellers. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken.

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

On July 28, 2015, the Company entered into an NOLs rights plan (the "Rights Plan") designed to preserve stockholder value and the value of our NOLs by acting as a deterrent to any person acquiring beneficial ownership of 4.9% or more of the Company's outstanding common stock without the approval of our board of directors. The Rights Plan may discourage existing 5% common stockholders from selling their interest in a single block, which may impact the liquidity of the Company's common stock, may deter institutional investors from investing in our common stock, and may deter potential acquirers from making premium offers to acquire the Company, factors which may depress the market price of our common stock. We can make no assurances the Rights Plan will be effective in meeting its intended objectives, including to deter a change in control and protecting or realizing NOLs.

If we were to experience an ownership change, we could be limited in our ability to use NOLs arising prior to the ownership change to offset future taxable income.

As of December 31, 2017, we had NOLs of $1,737.7 million. If we were to experience an "ownership change," as determined under Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"), our ability to offset taxable income arising after the ownership change with NOLs arising prior to the ownership change would be limited, possibly substantially. An ownership change would establish an annual limitation on the amount of our pre-change NOLs we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate. In general, an ownership change will occur if there is a cumulative increase in our ownership of more than 50 percentage points by one or more "5% shareholders" (as defined in the Code) at any time during a rolling three-year period.

Our business could be negatively impacted by security threats, including cyber-security threats, and other disruptions.

As an oil and natural gas producer, we face various security threats, including cyber-security threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the safety of our employees, threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. Cyber-security attacks in particular are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows.

We may be able to incur substantially more debt. This could exacerbate the risks associated with our indebtedness.

Despite our current level of indebtedness, we and our subsidiaries may be able to incur substantial additional indebtedness in the future, including under our SN UnSub Credit Agreement. As of December 31, 2017, we had $1.93 billion of debt outstanding, net of premium, discount and debt issuance costs, the majority of which was attributable to the Senior Notes (as defined in “Item 8. Financial Statements and Supplementary Data – Note 6, Debt”), a borrowing base of $350 million (with an aggregate elected commitment amount of $300 million) under our prior revolving credit facility for secured revolver borrowings, and a borrowing base of $330 million under our SN UnSub Credit Agreement. On February 14, 2018, we issued $500 million in aggregate principal amount of our 7.25% Senior Secured Notes and amended and restated our prior revolving credit facility. See ‘Item 8. Financial Statements and Supplementary Data – Note 20, Subsequent Events.” Subject to compliance with specified borrowing conditions and other covenants, the indenture for the 7.25% Senior Secured Notes and the indenture for the Senior Notes would allow us to incur additional debt. Our increased indebtedness could adversely affect our business. In particular, the incurrence of additional debt could increase our vulnerability to sustained, adverse macroeconomic weakness, limit our ability to obtain further financing and limit our ability to pursue certain operational and strategic opportunities. If new debt is added to our current debt levels, the related risks that we and our subsidiaries now face could intensify.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

We will be subject to interest rate risk in connection with borrowings under our amended and restated credit facility and our SN UnSub Credit Agreement, which bear interest at variable rates. Interest rate changes could affect the amount of our interest payments under these credit facilities and, accordingly, our future earnings and cash flows, assuming other factors are held constant. We currently do not have any interest rate hedging arrangements with respect to our credit facilities. In the future, we may enter into interest rate swaps that involve the exchange of fixed-for-floating interest rate payments in order to reduce our exposure to interest rate volatility; however, any swaps we enter into may not fully mitigate our interest rate risk. A significant increase in prevailing interest rates that results in a substantial increase in the interest rates applicable to our indebtedness could substantially increase our interest expense and have a material adverse effect on our financial condition and results of operations.

Restrictive covenants may adversely affect our operations.

Our amended and restated credit facility, the indentures governing the Senior Notes, the indenture governing the 7.25% Senior Secured Notes and our SN UnSub Credit Agreement contain a number of restrictive covenants that impose significant operating and financial restrictions on us and may limit our ability to engage in acts that may be in our long-term best interest, including our ability, among other things, to:

- incur or assume additional debt or provide guarantees in respect of obligations of other persons;
- issue redeemable stock and preferred stock;
- pay dividends or distributions or redeem or repurchase capital stock;
- prepay, redeem or repurchase certain debt;
- make loans and investments;
- create or incur liens;
- restrict distributions from our subsidiaries;
- sell assets and capital stock of our subsidiaries;

- consolidate or merge with or into another entity, or sell all or substantially all of our assets; and
- enter into new lines of business.

A breach of the covenants under the indentures governing the Senior Notes, the indenture governing the 7.25% Senior Secured Notes, the covenants under our amended and restated credit facility or the covenants under our SN UnSub Credit Agreement could result in an event of default under the applicable indebtedness. An event of default may allow the creditors to accelerate the related debt and may result in an acceleration of any other debt that contains a cross-acceleration or cross-default provision (however, a default under our amended and restated credit facility, the Senior Notes or the 7.25% Senior Secured Notes would not result in a default under or the acceleration of our SN UnSub Credit Agreement and a default under our SN UnSub Credit Agreement would not result in a default under or the acceleration of our amended and restated credit facility, Senior Notes or 7.25% Senior Secured Notes). In addition, an event of default under our amended and restated credit facility or our SN UnSub Credit Agreement would permit the lenders under the relevant facility to terminate all commitments to extend further credit under that facility. If we were unable to repay those amounts or amounts due to holders of our 7.25% Senior Secured Notes, the lenders under our amended and restated credit facility or our SN UnSub Credit Agreement or the holders of our 7.25% Senior Secured Notes, as applicable, could proceed against the collateral granted to them to secure that debt. Additionally, if we do not repay the approximately $24 million in borrowings due under Sanchez Resources, LLC's ("Sanchez Resources") credit facility or successfully renegotiate the terms of such facility, then the administrative agent or the lenders under that facility could proceed against the collateral securing that debt, consisting of substantially all of Sanchez Resources' TMS assets (approximately 12,500 net acres). See "Item 8. Financial Statements and Supplementary Data – Note 10. Related Party Transactions".

We have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business, remain in compliance with debt covenants and make payments on our debt.

The aggregate amount of our outstanding indebtedness could have important consequences for us, including the following:

- any failure to comply with the obligations of any of our debt agreements, including financial and other restrictive covenants, could result in an event of default under the agreements governing such indebtedness;
- the covenants contained in our debt agreements limit our ability to borrow money in the future for acquisitions, capital expenditures or to meet our operating expenses or other general corporate obligations and may limit our flexibility in operating our business;
- we may have a higher level of debt than some of our competitors, which may put us at a competitive disadvantage;
- we may be more vulnerable to economic downturns and adverse developments in our industry or the economy in general, especially extended or further declines in oil and natural gas prices; and
- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We cannot be certain that our cash flow from operations will be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations. If we do not have enough cash to service our debt, we may be required to refinance all or part of our existing debt, sell assets, borrow more money or raise equity. We may not be able to refinance our debt, sell assets, borrow more money or raise equity on terms acceptable to us, if at all.

Because we have no plans to pay dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in us.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors may deem relevant. Covenants contained in our amended and restated credit facility, future credit facilities we may enter into, our indentures and the certificates of designations for our preferred stock restrict our ability to pay dividends on our common stock. In addition, the Delaware General Corporation Law (the “DGCL”) permits payment of dividends only out of a corporation’s surplus, which is defined as the excess of net assets (total assets less total liabilities) over a corporation’s capital as determined under the DGCL. If commodity prices decline, the value of our net assets will decline and, accordingly, our ability to lawfully declare and pay dividends may also decline. Investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Investors seeking cash dividends should not purchase our common stock.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common process used by oil and natural gas exploration and production operators in the completion of certain oil and natural gas wells whereby water, sand and chemicals are injected under pressure into subsurface formations to stimulate production of oil and/or natural gas. Hydraulic fracturing is generally exempt from federal regulation, and thus the process is typically regulated by state agencies. Nevertheless, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Underground Injection Control or UIC Program. In Texas, Louisiana and Mississippi, where we maintain acreage, the EPA is encouraging state programs to review and consider EPA guidance in these areas. In addition, the EPA previously announced its plans to develop a Notice of Proposed Rulemaking by June 2018, which would describe a proposed mechanism – regulatory, voluntary, or a combination of both – to collect data on hydraulic fracturing chemical substances and mixtures.

On May 12, 2016, the EPA amended its regulations to impose new standards for methane and VOC emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector. However, in a March 28, 2017 executive order, President Trump directed the EPA to review the 2016 regulations and, if appropriate, to initiate a rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation’s energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. On June 16, 2017, the EPA published a proposed rule to stay for two years certain requirements of the 2016 regulations, including fugitive emission requirements. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing or the disposal of produced water and flowback fluid in underground injection wells. Also, some states have adopted, and other states are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process, and a number of lawsuits and enforcement actions have been initiated across the country alleging that hydraulic fracturing practices have induced seismic activity and adversely impacted drinking water supplies, use of surface water, and the environment generally. These proceedings or regulations or any other new laws or regulations that significantly restrict hydraulic fracturing or the disposal of produced water and flowback fluid in underground injection wells could make it more difficult or costly for us to drill and produce from conventional or tight formations, increase our costs of compliance and doing business and make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings.

Further federal, state and/or local laws governing hydraulic fracturing could result in additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such changes could cause us to incur substantial compliance costs, and compliance or the consequences of failure to comply by us could have a material adverse effect on our business, financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if additional federal, state and/or local laws are enacted. Please read “Item 1. Business – Environmental Matters and Regulation” for a description of the laws and regulations governing hydraulic fracturing.

Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could have a material adverse effect on our business.

State and federal regulatory agencies have recently focused on a possible connection between hydraulic fracturing related activities, particularly the underground injection of wastewater into disposal wells, and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In addition, a number of lawsuits have been filed in some states, most recently in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise to assess the relationship between seismicity and the use of such wells. For example, on October 28, 2014, the Commission adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water or other oil and gas waste to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed new disposal well. If the permittee or an applicant of a disposal well permit fails to demonstrate that the produced water or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the agency may deny, modify, suspend or terminate the permit application or existing operating permit for that well. The Commission has used this authority to deny permits for waste disposal wells.

We dispose of large volumes of produced water gathered from our drilling and production operations by injecting it into wells pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations that restrict our ability to use hydraulic fracturing or dispose of produced water gathered from our drilling and production activities by owned disposal wells, could have a material adverse effect on our business, financial condition and results of operations.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations. In addition, the third parties on whom we rely on for gathering and transportation services are also subject to complex federal, state and other laws that could adversely affect the cost, manner or feasibility of conducting our business.

Our oil and natural gas development and production operations are subject to complex and stringent laws and regulations. To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, financial condition and results of operations. Please read "Item 1. Business—Environmental Matters and Regulation" for a description of the laws and regulations that affect us.

In addition, the operations of the third parties on whom we rely for gathering and transportation services are also subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third-party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely could have a material adverse effect on our business, financial condition and results of operations. Please read "Item 1. Business—Environmental Matters and Regulation" for a description of the laws and regulations that affect the third parties on whom we rely.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

In recent years, federal, state and local governments have taken steps to reduce emissions of GHGs. The EPA has finalized a series of GHG monitoring, reporting and emission control rules for the oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of the states have already taken measures to reduce emissions of GHGs primarily through the development of GHG emission inventories and/or regional GHG cap-and-trade programs.

Furthermore, in December 2015, the United States participated in the 21st Conference of the Parties (COP-21) of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature, and to conserve and enhance sinks and reservoirs of GHGs. The Agreement went into effect on November 4, 2016 and establishes a framework for the parties to cooperate and report actions to reduce GHG emissions. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement, and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international record.

Restrictions on GHG emissions that may be imposed could adversely affect the oil and gas industry. The adoption of any legislation or regulations that otherwise limit emissions of GHGs from our equipment and operations could require us to incur increased operating costs, such as costs to monitor and report GHG emissions, purchase and operate emissions control systems to reduce emissions of GHGs associated with our operations, acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thus could adversely affect demand for the oil and natural gas that we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations. Please read "Item 1. Business—Environmental Matters and Regulation."

In addition, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Furthermore, claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury or property damages or other liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Moreover, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially hotter or colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

Our operations are subject to environmental and operational safety laws and regulations that may expose us to significant costs and liabilities.

We may incur significant delays, costs and liabilities as a result of stringent and complex environmental, health and safety requirements applicable to our oil and natural gas development and production operations. These laws and regulations may impose numerous obligations applicable to our operations, including that they may (i) require the acquisition of permits to conduct exploration, drilling and production operations; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling, production and transportation activities; (iii) govern the sourcing and disposal of water used in the drilling and completion process; (iv) limit or prohibit drilling or injection activities on certain lands lying within wilderness, wetlands, seismically active areas, and other protected areas; (v) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; (vi) result in the suspension or revocation of necessary permits, licenses and authorizations; (vii) impose substantial liabilities for pollution resulting from drilling and production operations; and (viii) require that additional pollution controls be installed. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly compliance or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to our handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to our operations, and as a result of historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to strict and joint and several liability for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination or the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property or natural resource damages. In addition, the risk of accidental spills or releases could expose us to significant liabilities that could have a material adverse effect on our business, financial condition and results of operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste control, handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our competitive position, business, financial condition and results of operations. We may not be able to recover some or any of these costs from insurance. Please read “Item 1. Business—Environmental Matters and Regulation” for more information.

Derivatives reform legislation and related regulations could have an adverse effect on our ability to hedge risks associated with our business.

The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandates that the Commodity Futures Trading Commission, or the CFTC, the SEC and certain federal regulators of financial institutions, or Prudential Regulators, adopt rules or regulations implementing the Dodd-Frank Act and providing definitions of terms used in the Dodd-Frank Act. The Dodd-Frank Act establishes margin requirements and requires clearing and trade execution practices for certain market participants and may result in certain market participants needing to curtail or cease their derivatives activities.

Although some of the rules necessary to implement the Dodd-Frank Act remain to be adopted, the CFTC, the SEC and the Prudential Regulators have issued many rules to implement the Dodd-Frank Act, including a rule, which we refer to as the “Mandatory Clearing Rule,” requiring clearing of hedges, or swaps, that are subject to it (currently, only certain interest rate and credit default swaps, which we do not presently have), a rule, which we refer to as the “End User Exception,” establishing an “end user” exception to the Mandatory Clearing Rule, a rule, which we refer to as the “Margin Rule,” setting forth collateral requirements in connection with swaps that are not cleared and also an exception to the Margin Rule for end users that are not financial end users, which exception we refer to as the “Non-Financial End User Exception,” and a rule, subsequently vacated by the United States District Court for the District of Columbia and remanded to the CFTC for further proceedings, imposing position limits on energy derivatives. On multiple occasions, most recently in December 2016, the CFTC proposed but did not adopt other position limit rules on energy derivatives. Such proposed rules have included exemptions from the position limits for swaps that constitute “bona fide hedging positions” within the definition of such term under such proposed rules, subject to the party claiming the exemption complying with the applicable filing, recordkeeping and reporting requirements of such proposed rules. It is not known whether the CFTC will adopt a rule which we refer to as a “Position Limit Rule” imposing position limits on energy derivatives or, if such a rule is adopted, whether such rule will include an exemption for “bona fide hedging positions”. Nor is it known if our hedging activities will constitute “bona fide hedging positions” under any such Position Limit Rule.

We qualify for the End User Exception and will utilize it if the Mandatory Clearing Rule is expanded to cover swaps in which we participate and we qualify for the Non-Financial End User Exception and will not be required to post margin under the Margin Rule, so we do not expect to be directly affected by any of such rules. However, most if not all of our hedge counterparties will be subject to mandatory clearing in connection with their hedging activities with parties who do not qualify for the End User Exception and will be required to post margin in connection with their hedging activities with other swap dealers, major swap participants, financial end users and other persons that do not qualify for the Non-Financial End User Exception. In addition, the European Union and other non-U.S. jurisdictions have enacted laws and regulations (including laws and regulations giving European Union financial authorities the power to write down amounts we may be owed on hedging agreements with counterparties subject to such laws and regulations and/or require that we accept equity interests in such counterparties in lieu of cash in satisfaction of such amounts), which we refer to collectively as “Foreign Regulations” which may apply to our transactions with counterparties subject to such Foreign Regulations. The Dodd-Frank Act, the rules which have been adopted and not vacated, and, to the extent that a Position Limit Rule is ultimately effected, such rule could significantly increase the cost of our derivative contracts, materially alter the terms of our derivative contracts, reduce the availability of derivatives to us that we have historically used to protect against risks that we encounter in our business, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. The Foreign Regulations could have similar effects. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations and Foreign Regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition, and our results of operations.

Tax laws and regulations may change over time, including the elimination of federal income tax deductions currently available with respect to oil and gas exploration and development.

Tax laws and regulations are highly complex and subject to interpretation, and the tax laws and regulations to which we are subject may change over time. Our tax filings are based upon our interpretation of the tax laws in effect in various jurisdictions at the time that the filings were made. If these laws or regulations change, or if the taxing authorities do not agree with our interpretation of the effects of such laws and regulations, it could have a material adverse effect on our business and financial condition.

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 Code. The Tax Act, among other things, (i) permanently reduces the U.S. corporate income tax rate, (ii) repeals the corporate alternative minimum tax, (iii) eliminates the deduction for certain domestic production activities, (iv) imposes new limitations on the utilization of net operating losses, and (v) provides for more general changes to the taxation of corporations, including changes to cost recovery rules and to the deductibility of interest expense, which may impact the taxation of oil and gas companies. The Tax Act is complex and far-reaching and we cannot predict with certainty the resulting impact its enactment will have on us. The ultimate impact of the Tax Act may differ from our estimates due to changes in interpretations and assumptions made by us as well as additional regulatory guidance that may be issued, and any such changes in our interpretations or assumptions could have an adverse effect on our business, results of operations, and financial condition.

In past years, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws, including, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current expensing of intangible drilling and development costs; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. While these specific changes are not included in the Tax Act, no accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. The elimination of such U.S. federal tax deductions, as well as any other changes to or the imposition of new federal, state, local or non-U.S. taxes (including the imposition of, or increases in production, severance or similar taxes) could have a material adverse effect on our business, financial condition and results of operations by increasing the after-tax costs we incur which would in turn make it uneconomic to drill some locations if commodity prices are not sufficiently high, resulting in lower revenues and decreases in production and reserves.

We are subject to anti-takeover provisions in our restated certificate of incorporation and amended and restated bylaws, our Rights Plan and Delaware law that could delay or prevent an acquisition of our company, even if the acquisition would be beneficial to our stockholders.

Provisions in our restated certificate of incorporation and amended and restated bylaws may delay or prevent an acquisition of us. These provisions may also frustrate or prevent any attempts by our stockholders to replace or remove our current management by making it more difficult for stockholders to replace members of our board of directors, who are responsible for appointing the members of our management team. Furthermore, because we are incorporated in Delaware, we are governed by the provisions of Section 203 of the DGCL, which prohibits, with some exceptions, stockholders owning in excess of 15% of our outstanding voting stock from merging or combining with us. In addition, the Company entered into the Rights Plan on July 28, 2015. The Rights Plan is designed to preserve stockholder value and the value of our NOLs by acting as a deterrent to any person acquiring beneficial ownership of 4.9% or more of the Company's outstanding common stock without the approval of our board of directors. Although not intended for this purpose, the Rights Plan has an anti-takeover effect. For more information on possible risks associated with our rights plan, please see "*—We adopted the Rights Plan, which though it was designed to preserve the value of our NOLs, may discourage the acquisition and sale of large blocks of our common stock and may result in significant dilution for certain stockholders.*" Finally, our amended and restated bylaws establish advance notice requirements for nominations for election to our board of directors and for proposing matters that can be acted upon at stockholder meetings. Although we believe these provisions together provide an opportunity to receive higher bids by requiring potential acquirers to negotiate with our board of directors, they would apply even if an offer to acquire us may be considered beneficial by some stockholders.

We are subject to legal proceedings and legal compliance risks.

We, including our officers and directors, are involved in various legal proceedings from time to time. Certain of these legal proceedings may be a significant distraction to management and could expose our Company to significant liability, including damages, fines, penalties and attorneys' fees and costs, any of which could have a material adverse effect on our business and results of operations.

For example, we recently settled or had dismissed, as applicable, derivative lawsuits initiated in 2013, which are discussed in more detail below in "Item 3. Legal Proceedings" and in "Item 8. Financial Statements and Supplementary Data — Note 15, Commitments and Contingencies."

We may have potential business conflicts of interest with members of the Sanchez Group regarding our past, ongoing and future relationships and the resolution of these conflicts may not be favorable to us.

Conflicts of interest may arise between members of the Sanchez Group and us in a number of areas relating to our past, ongoing and future relationships, including:

- labor, tax, employee benefit, indemnification and other matters arising under agreements with SOG;
- employee recruiting and retention;
- business opportunities that may be attractive to both members of the Sanchez Group and us; and
- business transactions that we enter into with members of the Sanchez Group.

We may not be able to resolve any potential conflicts, and, even if we do so, the resolution may be less favorable to us than if we were dealing with an unaffiliated party.

Finally, in connection with our initial public offering ("IPO"), we entered into several agreements with members of the Sanchez Group. In addition, at the closing of the Comanche Acquisition, we entered into management services agreements with SOG for it to perform various management service functions for SN UnSub and Blackstone and/or their affiliates. These agreements were made in the context of a related party transaction. The terms of these agreements may be more or less favorable to us than if they had been negotiated with unaffiliated third parties.

Pursuant to the terms of our restated certificate of incorporation, members of the Sanchez Group are not required to offer corporate opportunities to us, and our directors and officers may be permitted to offer certain corporate opportunities to members of the Sanchez Group before us.

Our board of directors includes persons who are also directors and/or officers of members of the Sanchez Group. Our restated certificate of incorporation provides that:

- members of the Sanchez Group are free to compete with us in any activity or line of business;
- we do not have any interest or expectancy in any business opportunity, transaction, or other matter in which members of the Sanchez Group engage or seek to engage merely because we engage in the same or similar lines of business;
- to the fullest extent permitted by law, members of the Sanchez Group will have no duty to communicate their knowledge of, or offer, any potential business opportunity, transaction, or other matter to us, and members of the Sanchez Group are free to pursue or acquire such business opportunity, transaction, or other matter for themselves or direct the business opportunity, transaction, or other matter to its affiliates; and

- if any director or officer of any member of the Sanchez Group who is also one of our officers or directors becomes aware of a potential business opportunity, transaction, or other matter (other than one expressly offered to that director or officer in writing solely in his or her capacity as our director or officer), that director or officer will have no duty to communicate or offer that business opportunity to us, and will be permitted to communicate or offer that business opportunity to such member of the Sanchez Group and that director or officer will not, to the fullest extent permitted by law, be deemed to have (1) breached or acted in a manner inconsistent with or opposed to his or her fiduciary or other duties to us regarding the business opportunity or (2) acted in bad faith or in a manner inconsistent with our best interests or those of our stockholders.

We depend on SOG to provide us with certain services for our business. The services that SOG provides to us may not be sufficient to meet our needs, and we may have difficulty finding replacement services or be required to pay increased costs to replace these services after our agreements with SOG expire.

Certain services required by us for the operation of our business, including 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, are provided by SOG pursuant to the Services Agreement. The services provided under the Services Agreement commenced on the date that the IPO closed and had an initial term of five years. The term automatically extends for additional 12-month periods and is terminable by either party at any time upon 180 days' written notice. See "Corporate Governance—Compensation Committee" in the proxy statement for the 2017 annual meeting of stockholders. While these services are being provided to us by SOG, our operational flexibility to modify or implement changes with respect to such services or the amounts we pay for them is limited. After the expiration or termination of this agreement, we may not be able to replace these services or enter into appropriate third-party agreements on terms and conditions, including cost, comparable to those that we will receive from SOG under our agreements with SOG.

In addition, SOG may outsource some or all of these services to third parties, and a failure of all or part of SOG's relationships with its outsourcing providers could lead to delays in or interruptions of these services. Our reliance on SOG and others as service providers and on SOG's outsourcing relationships, and our limited ability to control certain costs, could have a material adverse effect on our business, financial condition and results of operations.

Sector cost inflation could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and third party oilfield materials, service and supply costs are also subject to supply and demand dynamics. During periods of decreasing levels of industry exploration and production, such as occurred in 2015 and 2016, the demand for, and cost of, drilling rigs and oilfield services decreases. Conversely, during periods of increasing levels of industry activity, the demand for, and cost of, drilling rigs and oilfield services increase.

In the second half of 2016 and 2017, we witnessed a modest improvement in commodity prices. If this trend continues, and if the commodity price recovery is robust, we expect industry exploration and production activities to increase, resulting in higher demand for oilfield services and supplies, which could result in sector price inflation. In addition, the costs of such items could increase and their availability may become limited, particularly in basins of relatively higher activity.

A portion of our total outstanding shares is held by members of the Sanchez Group and may be sold into the market at any time. In addition, Blackstone and GSO (or their affiliates) received a substantial number of our securities in connection with the Comanche Acquisition. This could cause the market price of our common stock to drop significantly, even if our business is doing well.

As of February 23, 2018, members of the Sanchez Group owned, in the aggregate, approximately 14.2% of our outstanding common stock. These shares are generally eligible for resale in the public markets, subject to the volume, manner of sale and other limitations under Rule 144 of the Securities Act, if then applicable. In addition, at the closing of the Comanche Acquisition, we issued approximately 1.5 million shares of common stock to GSO and warrants to purchase approximately 1.9 million and 6.5 million shares of common stock, at an exercise price of $10.00 per share, to GSO and three affiliates of Blackstone, respectively, resulting in GSO and such Blackstone affiliates owning approximately 4.6% and 7.7% of our common stock, respectively, assuming that the warrants were fully exercised as of February 23, 2018. Following the conclusion of a two-year lockup period, shares of common stock issued pursuant to these warrants will be eligible for resale in the public markets, subject to the volume, manner of sale and other limitations under Rule 144 of the Securities Act, if then applicable. In addition, under certain circumstances, members of the Sanchez Group, GSO and such Blackstone affiliate have the right to require us to register the resale of their shares. Moreover, we have registered all of the shares of our common stock that we may issue under our employee benefit plans and there were an additional 8,251,002 shares available for future issuance to our directors, officers and employees as restricted stock or stock option awards pursuant to our Third Amended and Restated 2011 Long Term Incentive Plan (the "LTIP") as of December 31, 2017. These shares can be freely sold in the public market upon issuance unless, pursuant to their terms, these stock awards have transfer restrictions attached to them or are held by our affiliates, in which event such shares may be sold subject to the volume, manner of sale and other limitations under Rule 144 of the Securities Act, if then applicable. Sales of a substantial number of shares of our common stock, or the perception in the market that the holders of a large number of shares intend to sell shares, could reduce the market price of our common stock.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

The information required by Item 2 is contained in Item 1. Business.

Item 3. ***Legal Proceedings***

The information required by this Item is set forth in "Item 8. Financial Statements and Supplementary Data — Note 15, Commitments and Contingencies."

Item 4. ***Mine Safety Disclosures***

Not applicable.

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Market for Registrant's Common Equity. Shares of our common stock are traded on the NYSE under the symbol "SN." The following table sets forth the reported high and low sales prices of our common stock as reported by the NYSE for the periods indicated:

	Common Stock	
	High	**Low**
2017:		
First Quarter	$ 14.24	$ 8.41
Second Quarter	$ 9.76	$ 5.91
Third Quarter	$ 7.48	$ 4.04
Fourth Quarter	$ 5.60	$ 3.75

	Common Stock	
	High	**Low**
2016:		
First Quarter	$ 6.35	$ 2.06
Second Quarter	$ 9.83	$ 4.84
Third Quarter	$ 9.49	$ 5.64
Fourth Quarter	$ 10.14	$ 5.90

On February 23, 2018, the last sale price of our common stock, as reported on the NYSE, was $3.72 per share.

Holders. The number of holders of record of our common stock was approximately 245 on February 23, 2018, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or a bank.

Preferred Dividends. We pay preferred dividends quarterly, in arrears, on each January 1, April 1, July 1 and October 1, when and if declared by the Company's board of directors on our Series A Convertible Perpetual Preferred Stock ("Series A Preferred Stock") in the amount of 4.875%, and Series B Convertible Perpetual Preferred Stock ("Series B Preferred Stock") in the amount of 6.50%. The Company may, at its option, pay dividends in cash and, subject to certain conditions, common stock or any combination thereof. As of December 31, 2017, we have paid approximately $56.8 million in dividends to holders of our Series A and Series B Preferred Stock since their respective issuances. The dividends accrued for the period from April 1 to July 31, August 1 to September 30, and October 1 to December 31, 2016, were declared by the Board and paid with the Company's common stock. Additionally, the dividends accrued for the period from January 1 to March 31, April 1 to July 31, August 1 to September 30, and October 1 to December 31, 2017, were declared by the Board and paid with the Company's common stock.

We have not paid any cash dividends on our common equity since our inception. Although our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities, we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future. In addition, covenants contained in our amended and restated credit facility, future credit facilities we may enter into, our indentures and the certificates of designations for our preferred stock restrict our ability to pay dividends on our common stock and the DGCL permits payment of dividends only out of a corporation's surplus, which is defined as the excess of net assets (total assets less total liabilities) over a corporation's capital as determined under the DGCL. We currently intend to retain future earnings to finance current operations and the future expansion of our business.

Securities Authorized for Issuance Under Equity Compensation Plans. The following table sets forth certain information as of December 31, 2017 regarding the LTIP. The LTIP was approved by our stockholders on May 24, 2016, which increased the number of the shares of our common stock available for incentive awards pursuant to the LTIP's predecessor, which was approved by our stockholders on May 21, 2015.

	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available For Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Plan Category:			
Equity Compensation Plans Approved by Stockholders	—	N/A	8,251,002 (1)
Equity Compensation Plans Not Approved by Stockholders	N/A	N/A	N/A
Total	—	—	8,251,002

(1) The maximum number of shares that may be delivered pursuant to the LTIP is limited to 17,239,790 shares plus 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 our board of directors and compensation committee; provided, however, that shares withheld to satisfy tax withholding obligations are not considered to be delivered under the LTIP.

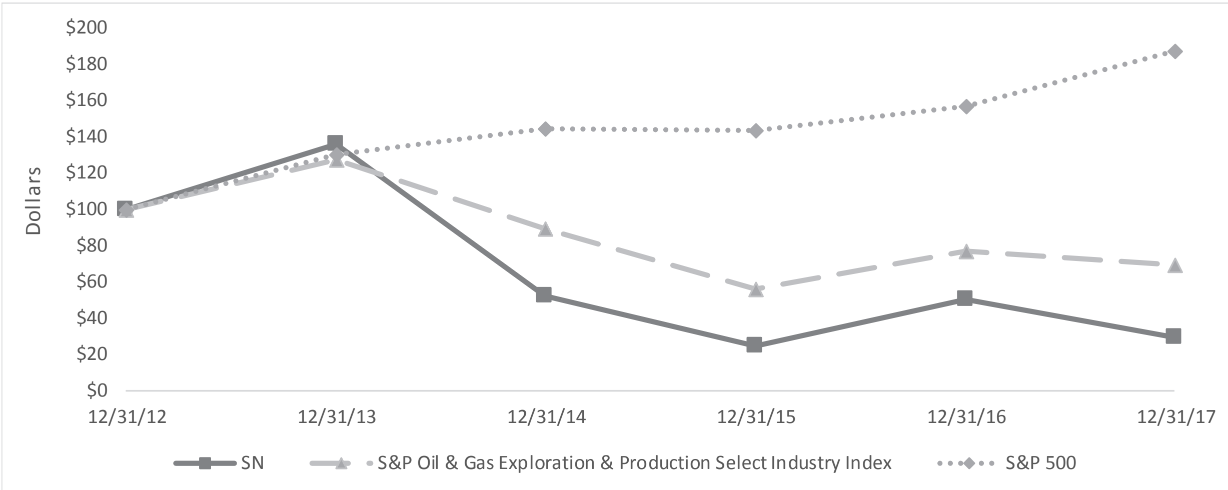
Recent Sales of Unregistered Securities. All sales of unregistered securities within the last fiscal year have been previously reported in our Quarterly Reports on Form 10-Q and/or Current Reports on Form 8-K.

Repurchases of Equity Securities. Neither we nor any "affiliated purchaser" repurchased any of our equity securities in the quarter ended December 31, 2017.

Comparative Stock Performance

The performance graph below compares the cumulative total stockholder return for our common stock to that of the Standard and Poor's, or S&P, 500 Index and the S&P 500 Oil & Gas Exploration and Production Index for the period from December 31, 2012 to December 31, 2017. "Cumulative total return" means the change in share price during the measurement period divided by the share price at the beginning of the measurement period. The graph assumes an investment of $100 was made in the Company's common stock and in each of the S&P 500 Index and the S&P 500 Oil & Gas Exploration and Production Index at the closing market price on December 31, 2012.

COMPARISON OF CUMULATIVE TOTAL RETURN
AMONG SANCHEZ ENERGY CORPORATION, THE S&P 500 INDEX,
AND THE S&P 500 OIL & GAS EXPLORATION AND PRODUCTION INDEX



Note: The stock price performance of our common stock is not necessarily indicative of future performance.

The above information under the caption "Comparative Stock Performance" shall not be deemed to be "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act or the Exchange Act except to the extent that we specifically request that such information be treated as "soliciting material" or specifically incorporate such information by reference into such a filing.

Item 6. *Selected Financial Data*

The selected financial data table below shows our historical consolidated financial data as of and for each of the five years in the period ended December 31, 2017. The selected financial data is derived from our audited historical financial statements.

The selected financial data should be read together with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data" included in this Annual Report on Form 10-K. Financial information for 2017 and prior years has been recast to reflect retrospective application of the successful efforts method of accounting. See "Item 8. Financial Statements and Supplementary Data – Note 2. Basis of Presentation and Summary of Significant Accounting Policies." Factors that materially affect the comparability of this information are disclosed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(in thousands, except per share amounts)				
REVENUES:					
Oil sales	$ 400,045	$ 241,766	$ 307,971	$ 538,887	$ 290,322
Natural gas liquids sales	171,139	81,744	69,011	66,989	13,013
Natural gas sales	169,147	107,816	98,797	60,188	11,085
Total revenues	740,331	431,326	475,779	666,064	314,420
OPERATING COSTS AND EXPENSES:					
Oil and natural gas production expenses	244,461	155,660	154,672	93,581	35,669
Production and ad valorem taxes	36,615	19,633	26,870	37,787	17,334
Exploration expenses	5,755	403	1,982	4,238	4,852
Depreciation, depletion, amortization and accretion	177,078	147,485	264,379	282,193	134,876
Impairment of oil and natural gas properties	39,574	47,381	723,971	1,060,328	16,668
General and administrative (1)	144,401	110,081	74,160	63,692	47,951
Total operating costs and expenses	647,884	480,643	1,246,034	1,541,819	257,350
Operating income (loss)	92,447	(49,317)	(770,255)	(875,755)	57,070
Other income (expense):					
Interest income	836	856	442	193	187
Other income (expense)	11,102	134	(2,605)	96	(75)
Gain on disposal of assets	81,955	85,322	—	—	—
Interest expense	(140,163)	(126,973)	(126,399)	(89,800)	(30,934)
Earnings from equity investments	779	3,466	—	—	—
Net gains (losses) on commodity derivatives	(6,100)	(53,149)	172,886	137,205	(16,938)
Total other income (expense)	(51,591)	(90,344)	44,324	47,694	(47,760)
Income (loss) before income taxes	40,856	(139,661)	(725,931)	(828,061)	9,310
Income tax benefit (expense)	2,336	(1,825)	(158)	—	—
Net income (loss)	43,192	(141,486)	(726,089)	(828,061)	9,310
Less:					
Preferred stock dividends	(15,948)	(15,948)	(16,008)	(33,590)	(18,525)
Preferred unit dividends and distributions	(44,259)	—	—	—	—
Preferred unit amortization	(18,039)	—	—	—	—
Net income allocable to participating securities(2)(3)	—	—	—	—	—
Net loss attributable to common stockholders	$ (35,054)	$ (157,434)	$ (742,097)	$ (861,651)	$ (9,215)
Net loss per common share - basic and diluted	$ (0.46)	$ (2.67)	$ (12.97)	$ (16.46)	$ (0.25)
Weighted average number of shares used to calculate net loss attributable to common stockholders - basic and diluted (4)	75,608	58,900	57,229	52,338	36,379

(1) Includes non-cash stock based compensation expense of $22.9 million, $25.0 million, $14.8 million, $12.8 million and $17.8 million for the years ended December 31, 2017, 2016, 2015, 2014 and 2013, respectively. Also includes acquisition and divestiture costs of $30.5 million, $8.4 million, $3.8 million, $1.8 million and $4.1 million for the years ended December 31, 2017, 2016, 2015, 2014 and 2013, respectively.

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

(3) For the years ended December 31, 2017, 2016, 2015 and 2014 no losses were allocated to participating restricted stock because such securities do not have a contractual obligation to share in the Company's losses.

(4) The year ended December 31, 2017 excludes 2,755,893 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 and 100,000 contingently issuable shares from the calculation of the denominator for diluted earnings per common share as these shares were anti-dilutive. The year ended December 31, 2016 excludes 2,113,462 shares of weighted average restricted stock and 12,554,481 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 earnings per common share as these shares were anti-dilutive. The year ended December 31, 2015 excludes 2,663,010 shares of weighted average restricted stock and 12,529,314 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 earnings per common share as these shares were anti-dilutive. The year ended December 31, 2014 excludes 1,732,888 shares of weighted average restricted stock and 13,527,738 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 earnings per common share as these shares were anti-dilutive. The year ended December 31, 2013 excludes 757,963 shares of weighted average restricted stock and 14,979,225 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 earnings per common share as these shares were anti-dilutive.

	As of December 31,				
	2017	2016	2015	2014	2013
			(in thousands)		
Balance Sheet Data:					
Working capital	$ (111,730)	$ 376,901	$ 490,205	$ 412,798	$ 54,061
Total assets [(1)]	$ 2,470,635	$ 1,332,211	$ 1,440,669	$ 2,162,146	$ 1,592,701
Long term debt, net of premium, discount and debt issuance costs[(1)]	$ 1,930,683	$ 1,712,767	$ 1,705,927	$ 1,698,095	$ 573,452
Total stockholders' equity (deficit)	$ (469,140)	$ (683,982)	$ (559,483)	$ 167,735	$ 831,725

	Year Ended December 31,				
	2017	2016	2015	2014	2013
			(in thousands)		
Cash Flow Data:					
Net cash provided by operating activities(1)	$ 292,089	$ 182,754	$ 270,576	$ 411,714	$ 184,682
Net cash used in investing activities	$ (1,382,800)	$ (108,234)	$ (292,349)	$ (1,357,026)	$ (1,088,533)
Net cash provided by (used in) financing activities(1)	$ 773,228	$ (7,651)	$ (16,893)	$ 1,265,495	$ 1,007,033

(1) As a result of the adoption of ASU No. 2016-09 on a retrospective basis as of the quarter ended March 31, 2017, the net cash provided by operating activities and net cash provided by (used in) financing activities as of December 31, 2016, 2015, 2014 and 2013 were reduced by approximately $1.9 million, $0.5 million, $0.6 million and $0.2 million, respectively. These retrospective changes are reflected in the net cash provided by operating activities and net cash provided by (used in) financing activities amounts in the table above. See further discussion on the adoption of ASU 2016-09 in "Item 8. Financial Statements and Supplementary Data — Note 2, Basis of Presentation and Summary of Significant Accounting Policies."

Non-GAAP Financial Measures

PV-10

PV-10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable financial measure in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"). PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10%. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure. Our PV-10 measure and the Standardized Measure do not purport to present the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV-10 to the Standardized Measure at December 31, 2017 for our proved reserves (in millions):

	Proved Reserves
PV-10	$ 1,886.1
Present value of future income taxes discounted at 10%	—
Standardized Measure (1)	$ 1,886.1

(1) Standardized measure is calculated in accordance with ASC Topic 932, Extractive Activities—Oil and Gas. For further information regarding the calculation of the standardized measure, see "Supplementary Information on Oil and Natural Gas Exploration, Development and Production Activities (Unaudited)" included in "Item 8. Financial Statements and Supplementary Data."

Adjusted G&A and Adjusted G&A per Boe

We present Adjusted G&A expense in addition to our reported G&A expense in accordance with U.S. GAAP. Adjusted G&A is reported herein because this measure is commonly used by management, analysts and investors as an indicator of cost management and operating efficiency on a comparable basis from period to period. In addition, management believes Adjusted G&A per Boe is used by analysts and others in valuation, comparison and investment recommendations of companies in the oil and gas industry to allow for analysis of G&A spend without regard to stock-based compensation programs which can vary substantially from company to company. Adjusted G&A per Boe should not be considered as an alternative to, or more meaningful than, total G&A per Boe as determined in accordance with U.S. GAAP and may not be comparable to other similar titled measures of other companies. We define Adjusted G&A as G&A:

Less:

- Stock-based compensation expense; and
- Certain costs related to acquisitions and divestitures.

The following table presents a reconciliation of our G&A to Adjusted G&A (in thousands, except per Boe data):

	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(in thousands, except per Boe data)				
General and administrative expense	$ 144,401	$ 110,081	$ 74,160	$ 63,692	$ 47,951
Stock-based compensation expense included in G&A	22,909	24,961	14,831	12,843	17,751
Acquisition and divestiture costs included in G&A	30,527	8,404	3,814	1,808	4,129
Adjusted G&A	$ 90,965	$ 76,716	$ 55,515	$ 49,041	$ 26,071
Average unit costs per Boe:					
General and administrative expense	$ 5.63	$ 5.64	$ 3.87	$ 5.72	$ 12.39
Stock-based compensation expense included in G&A	$ 0.89	$ 1.28	$ 0.77	$ 1.15	$ 4.58
Acquisition and divestiture costs included in G&A	$ 1.19	$ 0.43	$ 0.20	$ 0.16	$ 1.07
Adjusted G&A per Boe	$ 3.55	$ 3.93	$ 2.90	$ 4.41	$ 6.74

Item 7. ***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 consolidated financial statements and related notes set forth in "Item 8. Financial Statements and Supplementary Data," our consolidated financial data set forth in "Item 6. Selected Financial Data" and the risk factors identified in "Item 1A. Risk Factors" of this Annual Report on Form 10-K.

Our estimated proved reserve information as of December 31, 2017 contained in this Annual Report on Form 10-K is based on a report prepared by Ryder Scott, our independent reserve engineers.

Certain items in our discussion below are forward-looking statements. These forward looking statements involve risks and uncertainties. A number of factors could cause actual results to differ materially from those implied or expressed in such forward-looking statements. Please see "Cautionary Note Regarding Forward-Looking Statements."

Business Overview

Sanchez Energy Corporation, a Delaware corporation formed in 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 TMS in Mississippi and Louisiana, which offers potential future development opportunities. As of December 31, 2017, we have assembled approximately 487,000 gross leasehold acres (285,000 net acres) in the Eagle Ford Shale.

For the year 2018, we plan to invest substantially all of our 2018 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.

For further discussion of our business, including a description of various acquisitions completed during the periods presented in the consolidated financial statements, refer to "Item 1. Business—Overview."

Basis of Presentation

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

Our Properties

We and our predecessor entities have a long history in the Eagle Ford Shale, where, as of December 31, 2017, we have assembled approximately 487,000 gross leasehold acres (285,000 net acres) and have over 8,000 gross (3,700 net) specifically identified locations for potential future drilling. As of December 31, 2017, approximately 748 of these gross drilling locations represented proved undeveloped reserves. These locations were developed using existing geologic and engineering data. The approximately 7,252 additional gross drilling locations are specifically identified non-proven locations that have been identified by our management team. Although these approximate 7,252 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 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. See Item 1A. Risk Factors – "Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling."

For further discussion of our properties, including a description of recent well results in our core operating areas, refer to "Item 1. Business—Core Properties."

Recent Developments

Comanche Integration

Integration of the Comanche Assets continued during the fourth quarter 2017. As of December 31, 2017, we had brought 147 gross wells on-line since we closed the transaction on March 1, 2017, including 64 wells during the fourth quarter, 41 wells during the third quarter, and 42 wells during the second quarter. In addition, there are currently 71 wells awaiting completion within the Comanche Assets. With the Comanche Assets strategically located adjacent to our existing Catarina assets, and in close proximity to our Maverick operations, 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.

Conversion from Full Cost to Successful Efforts

During the fourth quarter of 2017, we changed from the full cost method to the successful efforts method in accounting for oil and gas exploration and development activities. Financial information for prior periods has been recast to reflect retrospective application of the successful efforts method, as prescribed by the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 932 "Extractive Activities – Oil and Gas." Although the full cost method of accounting for oil and gas exploration and development activities continues to be an acceptable alternative, the successful efforts method of accounting is the generally preferred method under U.S. GAAP and is more widely used in the industry such that the change improves the comparability of the Company's financial statements to its peers. Changing to the successful efforts method of accounting is expected to provide greater transparency in results of our assets, enhance operating decision making and capital allocation processes and eliminate proved property impairments based on historical prices, which are not indicative of fair value of our assets. 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. Successful efforts also provides for the assessment of potential property impairments under Accounting Standards Codification (ASC) 360 "Property, Plant, and Equipment" by comparing the net carrying value of oil and 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 gas properties exceeded 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 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.

Issuance of 2023 Secured Notes

On February14, 2018, we issued $500 million in aggregate principal amount of 7.25% Senior Secured Notes. Interest on the 2023 Secured Notes accrues from February 14, 2018 at the rate of 7.25% per annum, payable semiannually in cash in arrears on February 15 and August 15 of each year, commencing on August 15, 2018. The notes and the note guarantees are our and our subsidiary guarantor's general first lien secured obligations. The 7.25% Senior Secured Notes will mature on February 15, 2023, unless on October 10, 2022 either (i) some or all of our 6.125% Notes (as defined in "Item 8. Financial Statements and Supplementary Data – Note 6. Debt") are still outstanding and have not been defeased or (ii) we or any of our restricted subsidiaries have any outstanding indebtedness that was used to purchase, repurchase, redeem, defease or otherwise acquire or retire for value our 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 either of clause (i) or clause (ii), the 7.25% Senior Secured Notes will mature on October 14, 2022. The 7.25% Senior Secured Notes are secured by first-priority liens on substantially all of our subsidiary guarantor's assets. The 7.25% Senior Secured Notes are effectively junior to any obligations under our amended and restated credit facility and obligations under any hedging arrangements and cash management arrangements permitted to be secured on a first lien basis under our amended and restated credit facility, to the extent of the value of the collateral securing such obligations. See “Item 8. Financial Statements and Supplementary Data — Note 6, Debt” and “ – Note 20, Subsequent Events.”

Amended and Restated Credit Facility

On February 14, 2018, we amended and restated our revolving credit facility (our “amended and restated credit facility”) with RBC Capital Markets, LLC, as arranger, and Royal Bank of Canada, as agent and revolver lender (“RBC”). Our amended and restated credit facility provides for a $25 million first lien, “first-out” senior secured working capital and letter of credit facility. Availability under our amended and restated facility is at all times subject to customary conditions. The obligations under our amended and restated credit facility are guaranteed by all of our restricted subsidiaries that guarantee the Senior Notes and 7.25% Senior Secured Notes, and together with the 7.25% Senior Secured Notes, are secured by first-priority liens on substantially all of our and any subsidiary guarantor’s assets. 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 obligations under such hedging arrangements and cash management arrangements. See “Item 8. Financial Statements and Supplementary Data — Note 6. Debt.”

2018 Capital Program

Our 2018 capital budget of $420 to $470 million is focused on the development of our approximately 285,000 net acres in the Eagle Ford Shale. In 2018, we plan to invest approximately $407 million to $437 million, or 100%, of our drilling and completion budget to complete 196 gross (87 net) Eagle Ford Shale wells. We also plan to invest $13 million to $33 million for facilities, leasing and seismic activities. This 2018 capital budget represents a decrease of approximately $100 million (at the midpoint) when compared to 2017 capital spending. The decrease in our 2018 capital budget is attributable to reduced activity levels in the Maverick and Palmetto assets, with similar capital allocation to the Catarina assets and SN Comanche Assets.

The following table presents summary data for each of our project areas as of December 31, 2017 as well as our drilling and completion budget for 2018 fiscal year:

			Identified Drilling Locations (2)		2018 Capital Expenditure Budget			
	Net Acreage	Average Working Interest (1)	Gross	Net	Net Wells Spud	Net Wells Completed	Capital (in millions)	% of Operating Capital
Catarina	106,000	100%	1,168	1,168	44	44	$ 205 - $ 215	50%
Comanche EF [4]	61,000	24%	5,364	1,300	33	19	$ 145 - $ 150	34%
Comanche - DUCs	—	21%	—	—	—	21	$ 40-$ 45	11%
Maverick	110,000	96%	1,057	1,016	3	3	$15 - $25	5%
Palmetto [3]	7,600	49%	443	217	1	—	$2	0%
Total Eagle Ford [5]	284,600	59%	8,032	3,701	81	87	$407 - $437	100%
TMS	37,000	100%	116	116	—	—	—	0%
Comanche - Pearsall	16,100	25%	1,555	382	—	—	—	0%
Other	4,700	25%	—	—	—	—	—	0%
Total	342,400	60%	9,703	4,199	81	87	$407 - $437	100%
Facilities, Leasing and Seismic							$13 - $33	0%
Total Capital Budget							$420 - $470	100%

(1) Average working interests reflect the Company’s average working interests in the leases it holds.

(2) As of December 31, 2017, we have over 8,000 gross (3,700 net) specifically identified locations for potential future drilling. As of December 31, 2017, approximately 748 of these gross drilling locations represented proved undeveloped reserves. These locations were developed using existing geologic and engineering data. The approximately 7,252 additional gross drilling locations are specifically identified non-proven locations that have been identified by our management team.

(3) The Palmetto area is not operated by the Company or its affiliates.

(4) SN Comanche Assets excluding approximately 16,100 net acres of deep rights only, which includes the Pearsall Shale.

(5) Approximately 40% of our net drilling locations in the Comanche EF area are held by SN UnSub.

Outlook

Commodity and capital markets have shown signs of improvement, however, 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 will in the future. We face continued uncertainty with respect to the demand for our products, commodity prices, service availability and costs, and our ability to fund capital projects. We continue to evaluate the possibility of certain non-core divestitures to improve liquidity and actively manage our portfolio and returns. We also reduced our 2018 capital budget by approximately $100 million, as compared to 2017, to better balance cash flows and focus on our highest return projects.

Based on current market prices and various production and cost assumptions, we believe internally generated cash flows and cash on hand at year-end 2017 combined with incremental cash raised from the February 14, 2018 issuance of the 7.25% Senior Secured Notes, as previously described, will be sufficient to fund our anticipated operating needs, debt service obligations, capital expenditures, and commitments and contingencies over a three-year planning horizon. We continuously evaluate our capital spending, operating and funding activities in light 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. In addition, we continuously review acquisition and divestiture opportunities involving third parties, SNMP and/or other members of the Sanchez Group.

The average oil price (WTI Cushing) used in the SEC pricing methodology for calculating the PV-10 and Standardized Measures, calculated as the unweighted arithmetic average of the first day of the month price for each month within the 12 month period ended December 31, 2017 was $51.34 per barrel and the average natural gas price, at Henry Hub, and calculated in the same manner, was $2.98 per MMBtu. At these price levels, SEC prices for oil and natural gas have increased approximately 20% and 20%, respectively, since December 31, 2016, and have increased approximately 3% and decreased approximately 1%, respectively, since September 30, 2017. Oil and natural gas prices experienced a significant drop in late 2014 and 2015. Prices recovered in 2016 and 2017, but still remain at levels lower than previously seen before the decline began in 2014. Crude oil prices declined from an average of $93.26 per Bbl in 2014 to $50.88 per Bbl in 2017 and natural gas prices declined from an average of $4.39 per MMBtu in 2014 to $2.99 per MMBtu in 2017.

Results of Operations

Revenue and Production

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

	Year Ended December 31,			Increase (Decrease)			
				2017 vs 2016		2016 vs 2015	
	2017	2016	2015	$	%	$	%
Net Production:							
Oil (MBbl)	8,217	6,370	7,165	1,847	29 %	(795)	(11)%
Natural gas liquids (MBbl)	8,342	5,960	5,754	2,382	40 %	206	4 %
Natural gas (MMcf)	54,651	43,189	37,594	11,462	27 %	5,595	15 %
Total oil equivalent (MBoe)	25,667	19,529	19,184	6,138	31 %	345	2 %
Average Sales Price Excluding Derivatives[(1)]:							
Oil ($ per Bbl)	$ 48.69	$ 37.95	$ 42.98	$ 10.74	28 %	$ (5.03)	(12)%
Natural gas liquids ($ per Bbl)	20.52	13.72	11.99	6.80	50 %	1.73	14 %
Natural gas ($ per Mcf)	3.10	2.50	2.63	0.60	24 %	(0.13)	(5)%
Oil equivalent ($ per Boe)	$ 28.84	$ 22.09	$ 24.80	$ 6.75	31 %	$ (2.71)	(11)%
Average Sales Price Including Derivatives[(2)]:							
Oil ($ per Bbl)	$ 50.12	$ 55.37	$ 60.28	$ (5.25)	(9)%	$ (4.91)	(8)%
Natural gas liquids ($ per Bbl)	20.52	13.72	11.99	6.80	50 %	1.73	14 %
Natural gas ($ per Mcf)	3.12	3.07	3.12	0.05	2 %	(0.05)	(2)%
Oil equivalent ($ per Boe)	$ 29.36	$ 29.03	$ 32.23	$ 0.33	1 %	$ (3.20)	(10)%
REVENUES[(1)]:							
Oil sales	$ 400,045	$ 241,766	$ 307,971	$ 158,279	65 %	$ (66,205)	(21)%
Natural gas liquids sales	171,139	81,744	69,011	89,395	109 %	12,733	18 %
Natural gas sales	169,147	107,816	98,797	61,331	57 %	9,019	9 %
Total revenues	$ 740,331	$ 431,326	$ 475,779	$ 309,005	72 %	$ (44,453)	(9)%

(1) Excludes the realized impact of derivative instruments.

(2) Includes the realized impact of derivative instruments.

Net Production. Net production increased from 19,529 MBoe in 2016 to 25,667 MBoe in 2017 mainly due to production from the Comanche area wells. The number of gross wells producing at year end and the production for the periods were as follows:

	Year Ended December 31,					
	2017		2016		2015	
	# Wells	MBoe	# Wells	MBoe	# Wells	MBoe
Comanche	1,582	9,089	—	—	—	—
Catarina	389	14,389	333	15,847	287	13,905
Maverick	63	1,477	36	888	24	409
Cotulla	—	30	49	1,279	121	2,107
Palmetto	84	346	76	511	72	874
Marquis	—	304	103	958	103	1,816
TMS / Other	47	32	14	46	14	73
Total	2,165	25,667	611	19,529	621	19,184

In 2017, 32% of our production was oil, 33% was NGLs and 35% was natural gas compared to 2016 production that was 33% oil, 30% NGLs and 37% natural gas. In 2015, 37% of our production was oil, 30% NGLs and 33% 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. Sales revenue for oil, NGLs and natural gas totaled approximately $740.3 million, $431.3 million, and $475.8 million for the years ended December 31, 2017, 2016 and 2015, respectively. Sales revenue for oil, NGLs and natural gas for the year ended December 31, 2017 increased $158.3 million, $89.4 million and $61.3 million, respectively, as compared to the year ended December 31, 2016.

The following tables provide an analysis of the impacts of changes in average realized prices and production volumes between the periods on our revenues from the year ended December 31, 2016 to the year ended December 31, 2017 (in thousands, except average sales price). The increase in revenue from the year ended December 31, 2016 to the year ended December 31, 2017 is primarily attributable to the increase in commodity prices and an increase in production volume.

	2017 Production Volume	2016 Production Volume	Production Volume Difference	2016 Average Sales Price	Revenue Increase/(Decrease) due to Production
Oil (MBbl)	8,217	6,370	1,847	$ 37.95	$ 70,063
Natural gas liquids (MBbl)	8,342	5,960	2,382	$ 13.72	$ 32,668
Natural gas (MMcf)	54,651	43,189	11,462	$ 2.50	$ 28,610
Total oil equivalent (MBoe)	25,667	19,529	6,138	$ 22.09	$ 131,341

	2017 Average Sales Price	2016 Average Sales Price	Average Sales Price Difference	2017 Production Volume	Revenue Increase/(Decrease) due to Price
Oil (MBbl)	$ 48.69	$ 37.95	$ 10.74	8,217	$ 88,216
Natural gas liquids (MBbl)	$ 20.52	$ 13.72	$ 6.80	8,342	$ 56,727
Natural gas (MMcf)	$ 3.10	$ 2.50	$ 0.60	54,651	$ 32,721
Total oil equivalent (MBoe)	$ 28.84	$ 22.09	$ 6.75	25,667	$ 177,664

Additionally, a 10% increase in our average realized sales prices, excluding the impact of derivatives, would have increased our revenues for the year ended December 31, 2017 by approximately $74.0 million, and a 10% decrease in our average realized sales prices, excluding the impact of derivatives, would have decreased our revenues for the year ended December 31, 2017 by approximately $74.0 million.

The following tables provide an analysis of the impacts of changes in average realized prices and production volumes between the periods on our revenues from the year ended December 31, 2015 to the year ended December 31, 2016 (in thousands, except average sales price):

	2016 Production Volume	2015 Production Volume	Production Volume Difference	2015 Average Sales Price	Revenue Increase/(Decrease) due to Production
Oil (MBbl)	6,370	7,165	(795)	$ 42.98	$ (34,140)
Natural gas liquids (MBbl)	5,960	5,754	206	$ 11.99	$ 2,470
Natural gas (MMcf)	43,189	37,594	5,595	$ 2.63	$ 14,704
Total oil equivalent (MBoe)	19,529	19,184	345	$ 24.80	$ (16,966)

	2016 Average Sales Price	2015 Average Sales Price	Average Sales Price Difference	2016 Production Volume	Revenue Increase/(Decrease) due to Price
Oil (MBbl)	$ 37.95	$ 42.98	$ (5.03)	6,370	$ (32,065)
Natural gas liquids (MBbl)	$ 13.72	$ 11.99	$ 1.73	5,960	$ 10,263
Natural gas (MMcf)	$ 2.50	$ 2.63	$ (0.13)	43,189	$ (5,685)
Total oil equivalent (MBoe)	$ 22.09	$ 24.80	$ (2.71)	19,529	$ (27,487)

Additionally, a 10% increase in our average realized sales prices, excluding the impact of derivatives, would have increased our revenues for the year ended December 31, 2016 by approximately $43.1 million, and a 10% decrease in our average realized sales prices, excluding the impact of derivatives, would have decreased our revenues for the year ended December 31, 2016 by approximately $43.1 million.

Operating Costs and Expenses

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

	Year Ended December 31,			Increase (Decrease)			
				2017 vs 2016		2016 vs 2015	
	2017	2016	2015	$	%	$	%
OPERATING COSTS AND EXPENSES:							
Oil and natural gas production expenses	$ 244,461	$ 155,660	$ 154,672	$ 88,801	57 %	$ 989	1 %
Production and ad valorem taxes	36,615	19,633	26,870	16,982	86 %	(7,237)	(27)%
Exploration expenses	5,755	403	1,982	5,352	1,328 %	(1,579)	(80)%
Depreciation, depletion, amortization and accretion	177,078	147,485	264,379	29,593	20 %	(116,894)	(44)%
Impairment of oil and natural gas properties	39,574	47,381	723,971	(7,807)	(16)%	(676,590)	(93)%
General and administrative (1)	144,401	110,081	74,160	34,320	31 %	35,921	48 %
Total operating costs and expenses	647,884	480,643	1,246,034	167,241	35 %	(765,390)	(61)%
Interest income and other income (expense)	11,938	990	(2,163)	10,948	*	3,153	(146)%
Gain on sale of oil and natural gas properties	81,955	85,322	—	(3,367)	(4)%	85,322	*
Interest expense	(140,163)	(126,973)	(126,399)	13,190	(10)%	574	(0)%
Earnings from equity investments	779	3,466	—	2,687	78 %	(3,466)	*
Net gains (losses) on commodity derivatives	(6,100)	(53,149)	172,886	47,049	(89)%	(226,035)	(131)%
Income tax benefit (expense)	2,336	(1,825)	(158)	4,161	(228)%	(1,667)	*

* Not meaningful.

(1) Includes non-cash stock-based compensation expense of $22.9 million, $24.9 million and $14.8 million for the years ended December 31, 2017, 2016 and 2015, respectively, and includes acquisition and divestiture costs of $30.5 million, $8.4 million and $3.8 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Oil and Natural Gas Production Expenses. Oil and natural gas production expenses are the costs incurred to produce our oil and natural gas, as well as the daily costs incurred to maintain our producing properties. Such costs also include field personnel costs, utilities, chemical additives, salt water disposal, maintenance, repairs and occasional well workover expenses related to our oil and natural gas properties. Our oil and natural gas production expenses increased 57% to $244.5 million for the year ended December 31, 2017, as compared to $155.7 million for the same period in 2016 and $154.7 million for the same period in 2015. The increase in oil and natural gas production expenses from 2015 to 2017 is primarily attributable to our increased production activities in the Eagle Ford Shale as a result of increased operating activity related to the wells in the Comanche area, acquired in 2017, and increased drilling in our Catarina acreage, acquired in 2014. Our average production expenses increased from $7.97 per Boe during the year ended December 31, 2016 to $9.52 per Boe for the year ended December 31, 2017. This increase was due primarily to the increase in marketing and transportation costs related to contracts signed in connection with the Comanche Acquisition and the increase in gathering and transportation costs associated with the Gathering Agreement related to the Western Catarina Midstream Divestiture. While we expect our oil and natural gas production expenses to increase as we add producing wells and vendor costs increase, we expect to continue our efficient operation of our properties.

Production and Ad Valorem Taxes. Production taxes are paid on produced oil and natural gas based upon a percentage of gross revenues or at fixed rates established by state or local taxing authorities. Ad valorem taxes are paid based upon the appraised fair market value of producing properties using an estimated discounted cash flow approach by a fixed rate established by state or local taxing authorities. Our production and ad valorem taxes totaled $36.6 million, $19.6 million and $26.9 million for the years ended December 31, 2017, 2016 and 2015, respectively. The tax increase from 2016 to 2017 is attributable to the increase in revenues of 72% between the periods. In addition, there was an increase in ad valorem taxes from 2016 to 2017 due to the addition of the SN Comanche Assets in March 2017. The tax decrease from 2015 to 2016 was attributable to the decrease in revenues of 9% between the periods and the decrease in appraised property values from the sustained decline in commodity prices and decrease in drilling activity during the period. Our average production and ad valorem taxes increased from $1.01 per Boe during the year ended December 31, 2016 to $1.43 per Boe for the year ended December 31, 2017. This increase in rate is attributable to the increase in property values during 2017 as compared to 2016 due to the rise in commodity prices during the period. In addition, the majority of our horizontal wells are characterized as tight gas wells, which apply a reduced production tax rate after certification from the state regulatory body. Until the Company receives the proper certification, the normal production tax rates are applied to the wells, and once the certification is approved, the reduced rates are applied and tax credits are received from the state. The timing of receipt of the certifications and tax credits vary from well to well.

Depreciation, Depletion and Amortization. Depletion, depreciation and amortization ("DD&A") reflects the systematic expensing of the capitalized costs incurred in the acquisition, successful exploration and development of oil and natural gas properties. We use the successful efforts method of accounting and accordingly, we capitalize all costs associated with the acquisition, successful exploration and development of oil and natural gas properties, including unproved and unevaluated property costs. Internal costs are capitalized only to the extent they are directly related to acquisition, exploration and development activities and do not include any costs related to production, selling or general corporate administrative activities. Capitalized costs of oil and natural gas properties are amortized using the units of production method based upon production and estimates of proved oil and natural gas reserve quantities. Unproved and unevaluated property costs are excluded from the amortizable base used to determine DD&A expense.

Our DD&A expense for the year ended December 31, 2017 increased to $177.1 million ($6.90 per Boe) from $147.5 million ($7.55 per Boe) in 2016 and $264.4 million in 2015 ($13.78 per Boe). Higher production in 2017 as compared to 2016 resulted in a $46.4 million increase in depletion expense and the change in depletion rate resulted in an offsetting $16.8 million decrease in depletion expense. Higher production in 2016 as compared to 2015 resulted in a $4.8 million increase in depletion expense and the change in depletion rate resulted in an offsetting $121.6 million decrease in depletion expense.

Impairment of Oil and Natural Gas Properties. We utilize the successful efforts method of accounting to account for our oil and natural gas exploration and development activities. Under this method of accounting, oil and natural gas properties are reviewed for impairment 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 recorded impairment of $39.6 million to our unproved oil and natural gas properties for the year ended December 31, 2017 due to a write-down of our TMS acreage to fair value. We recorded impairment of $43.7 million and $23.7 million to our unproved oil and natural gas properties due to acreage abandonment from changes in development plan for the years ended December 31, 2016 and December 31, 2015, respectively. We did not record a proved property impairment during the year ended December 31, 2017. During the year ended December 31, 2016, we recorded a proved property impairment of $3.7 million due to the decline of oil and natural gas prices during the first half of the year. During the year ended December 31, 2015, we recorded a proved property impairment of $700.3 million due to the significant decline in oil and natural gas prices during the year. The impact of lower commodity prices adversely affecting proved reserve values primarily contributed to the proved property impairment. Changes in production rates, levels of reserves, future development costs, and other factors will determine our actual impairment analyses in future periods.

General and Administrative Expenses. Our G&A expenses, totaled $144.4 million for the year ended December 31, 2017 compared to $110.1 million and $74.2 million for the same periods in 2016 and 2015, respectively. This increase was due primarily to additional costs for added personnel at SOG performing services for the Company and for consulting services and increased acquisition and divestiture costs incurred during 2017. Our G&A expenses per Boe were relatively unchanged at $5.64 per Boe for the year ended December 31, 2016 and $5.63 per Boe for the year ended December 31, 2017. Our G&A expenses totaled $110.1 million ($5.64 per Boe) for the year ended December 31, 2016 compared to $74.2 million ($3.87 per Boe) for the same period in 2015. This increase was due primarily to additional costs for added personnel at SOG performing services for the Company.

We recorded non-cash stock-based compensation expense (settled in common shares) of approximately $22.9 million ($0.89 per Boe) for the year ended December 31, 2017 as compared to $24.9 million ($1.28 per Boe) for the year ended December 31, 2016. The decrease was due primarily to a decrease in the stock price from period to period offset by the increase in awards made during the year and the associated amortization recognized. We recorded non-cash stock-based compensation expense of $14.8 million ($0.77 per Boe) for the year ended December 31, 2015. The increase from 2015 to 2016 was due primarily to the increase in awards made during the year and the associated amortization recognized in addition to the increase in the stock price from period to period. 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 significant acquisitions and divestitures that are included in G&A of $30.5 million ($1.19 per Boe) for the year ended December 31, 2017 primarily related to the Comanche Acquisition. Costs associated with significant acquisitions and divestitures included in G&A for the year ended December 31, 2016 totaled approximately $8.4 million ($0.43 per Boe) primarily related to the Carnero Gathering Disposition, Carnero Processing Disposition, Production Asset Transaction and Cotulla Disposition. Costs associated with significant acquisitions and divestitures included in G&A for the year ended December 31, 2015 totaled approximately $3.8 million ($0.20 per Boe) primarily related to the Palmetto Disposition and the Western Catarina Midstream Divestiture.

Adjusted G&A, excluding non-cash stock-based compensation expense and acquisition and divestiture costs included in G&A, totaled $91.0 million ($3.55 per Boe), $76.8 million ($3.93 per Boe), and $55.5 million ($2.89 per Boe) for the years ended December 31, 2017, 2016 and 2015, respectively.

Interest Expense. For the year ended December 31, 2017, interest expense totaled $140.2 million and included $12.6 million in amortization of debt issuance costs. The interest expense incurred during the year ended December 31, 2017 is primarily related to the 7.75% Notes (as defined in "Item 8. Financial Statements and Supplementary Data — Note 6. Debt") and 6.125% Notes. This is compared to the year ended December 31, 2016, for which interest expense totaled $127.0 million and included $7.8 million in amortization of debt issuance costs and to the year ended December 31, 2015, for which interest expense totaled $126.4 million and included $7.5 million in amortization of debt issuance costs and write-offs of previously incurred debt issuance costs in connection with the unused senior unsecured bridge facility obtained as part of the Catarina Acquisition that expired.

Commodity Derivative Transactions. We apply mark-to-market accounting to our derivative contracts; therefore, the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in other income and expenses. During the year ended December 31, 2017, we recognized a net loss of $6.1 million on our commodity derivative contracts, which included net gains of $13.1 million associated with the settlements of commodity derivative contracts, offset by mark to market losses of $19.2 million on unsettled commodity derivative contracts. The mark to market losses were a result of the increase in estimated future commodity prices as compared to the derivative settlement prices. The settlement gains realized during the period 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. During the year ended December 31, 2016, we recognized a net loss of $53.1 million on our commodity derivative contracts, which included net gains of $135.6 million associated with the settlements of commodity derivative contracts. During the year ended December 31, 2015, we recognized a net gain of $172.9 million on our commodity derivative contracts, which included net gains of $142.5 million associated with the settlements of commodity derivative contracts.

Income tax expense. For the year ended December 31, 2017, the Company recorded income tax benefit of $2.3 million. Our effective tax rate for the year ended December 31, 2017 was (5.7)% as compared to a statutory rate of 35%. The difference between the statutory rate and the Company's effective tax rate is primarily related to the valuation allowance of approximately $258.1 million recorded during the period and the impact to deferred taxes for the change in the federal income tax rate of 35% to 21% of approximately $227.4 million. For the year ended December 31, 2016, the Company recorded income tax expense of $1.8 million. Our effective tax rate for the year ended December 31, 2016 was (1.3)% as compared to a statutory rate of 35%. The difference between the statutory rate and the Company's effective tax rate is related to the valuation allowance of approximately $46.2 million recorded during the period. For the year ended December 31, 2015, the Company recorded income tax expense of $0.2 million. Our effective tax rate for the year ended December 31, 2015 was 0.0% as compared to a statutory rate of 35%. The difference between the statutory rate and the Company's effective tax rate is related to the valuation allowance of approximately $254.6 million recorded during the period.

Liquidity and Capital Resources

As of December 31, 2017, we had approximately $184.4 million in cash and cash equivalents, $250 million in available borrowing capacity at the elected commitment amount under our prior amended and restated credit facility, and $154.5 million in available borrowing capacity under the SN UnSub Credit Agreement, resulting in aggregate liquidity of approximately $588.9 million. For a description of our credit agreements and the indentures covering our Senior Notes in effect as of December 31, 2017, refer to "Item 8. Financial Statements and Supplementary Data — Note 6. Debt."

The Company recently announced its 2018 budget of approximately $420 million to $470 million, which represents an approximate $100 million reduction from annualized capital spending rates in the prior year. The 2018 budget is focused on lower risk development opportunities and reflects our commitment to financial discipline.

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 "Item 8. Financial Statements and Supplementary Data – Note 20, Subsequent Events."

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 December 31, 2017, we had not issued any shares of our common stock under the 2017 ATM.

See "Item 8. Financial Statements and Supplementary Data – Note 7, Stockholders' and Mezzanine Equity" for a description of our other financing activities during fiscal year 2017.

Based on current market prices and various production and cost assumptions, we believe internally generated cash flows and cash on hand at year-end 2017 combined with incremental cash raised from the February 14, 2018 issuance of the 7.25% Senior Secured Notes, as previously described, will be sufficient to fund our anticipated operating needs, debt service obligations, capital expenditures, and commitments and contingencies over a three-year planning horizon. We continuously evaluate our capital spending, operating and funding activities in light 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. In addition, we continuously review acquisition and divestiture opportunities involving third parties, SNMP and/or other members of the Sanchez Group.

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 years ended December 31, 2017, 2016 and 2015 are as follows (in thousands):

	Year Ended December 31,		
	2017	2016	2015
Cash Flow Data:			
Net cash provided by operating activities	$ 292,089	$ 182,754	$ 270,576
Net cash used in investing activities	$ (1,382,800)	$ (108,234)	$ (292,349)
Net cash provided by (used in) financing activities	$ 773,228	$ (7,651)	$ (16,893)

Net Cash Provided by Operating Activities. Net cash provided by operating activities was $292.1 million for the year ended December 31, 2017 compared to $182.8 million and $270.6 million for the same periods in 2016 and 2015, respectively. This increase was related to the favorable impact of higher average commodity prices between the periods and an increase in production.

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 $1,382.8 million for the year ended December 31, 2017 compared to $108.2 million and $292.3 million for the same periods in 2016 and 2015, respectively. Capital expenditures for leasehold and drilling activities for the year ended December 31, 2017 totaled $500.3 million, primarily associated with commencing completions operations on 129 DUCs acquired in the Comanche Acquisition, of which 105 had been brought online. We received a total of $14.3 million for the additional closings of the Cotulla Disposition that occurred in January and April 2017 as well as adjustments on the final settlement statement in September 2017. We received $44.0 million at the closing of the Marquis Disposition, $12.5 million for the SOII Disposition (as defined in "Item 8. Financial Statements and Supplementary Data – Note 17, Investments"), and an additional $105 million for the Javelina Disposition. In addition, we invested $18.6 million in other property and equipment during the year ended December 31, 2017.

For the year ended December 31, 2016, we incurred capital expenditures for leasehold and drilling activities of $312.9 million, primarily associated with bringing online 48 gross wells and expanding our acreage and asset development position in the Eagle Ford Shale through leasing. We spent approximately $36.5 million towards equity method investments prior to selling these investments in the Carnero Gathering Disposition and Carnero Processing Disposition for a combined cash inflow of approximately $92.5 million. In addition, we received cash of approximately $153.5 million for the Cotulla Disposition, purchased common units of SNMP for $25 million, and invested approximately $5.4 million in other assets.

For the year ended December 31, 2015, we incurred capital expenditures for leasehold and drilling activities of $654.2 million, primarily associated with bringing online 136 gross wells. We received total cash of approximately $427.6 million for the Palmetto Disposition and the Western Catarina Midstream Divestiture, while spending approximately $50.0 million towards equity method investments (further discussed in Note 17, "Investments") and $8.0 million for a buyout agreement with Sanchez Resources. In addition, we invested $8.1 million in other assets.

Net Cash Provided by (Used in) Financing Activities. Net cash flows provided by financing activities totaled $773.2 million for the year ended December 31, 2017 compared to net cash flows used in financing activities of $7.7 million and $16.9 million net cash flows used in financing activities for the same period in 2016 and 2015, respectively.

In association with the Comanche Acquisition in March 2017, we entered into the SN UnSub Credit Agreement and issued the SN UnSub Preferred Units (as defined in "Item 8. Financial Statements and Supplementary Data – Note 7, Stockholders' and Mezzanine Equity") for $500 million. From time to time, the Company has borrowed under our prior revolving credit facility and the SN UnSub Credit Agreement to make acquisitions, fund capital expenditures and provide liquidity for working capital and other general corporate purposes. As of December 31, 2017, we had outstanding borrowings of $50 million under the prior revolving credit facility and $250 million of the elected commitment amount of $300 million was available for future borrowings. Further, as of December 31, 2017, we had outstanding borrowings of $175.5 million under the SN UnSub Credit Agreement and approximately $154.5 million of the elected commitment amount of $330 million was available for future borrowings. In addition, we issued common stock for $135.9 million (net of underwriting discounts of $7.8 million). We made payments of $46.7 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 $1.4 million of employee taxes via withholding shares associated with stock-based compensation, which is considered a financing payment under the accounting guidance of ASU 2016-09. During the year ended December 31, 2017, we also made payments of $44.3 million for tax distributions to holders of the SN UnSub Preferred Units. The Partnership Agreement (as defined in "Item 8. Financial Statements and Supplementary Data – Note 7, Stockholders' and Mezzanine Equity") provides that tax distributions shall be treated as advances of any amounts holders of the SN UnSub Preferred Units are entitled to receive and shall be offset against any amounts holders of SN UnSub Preferred Units are entitled to receive.

During the year ended December 31, 2016, we made payments of $4.0 million for dividends on our Series A Preferred Stock and Series B Preferred Stock, payments of approximately $1.7 million for deferred financing costs associated with an amendment to the prior revolving credit facility, and payments of approximately $1.9 million of employee taxes via withholding shares associated with stock-based compensation.

During the year ended December 31, 2015, we made payments of $16.0 million for dividends on our Series A Preferred Stock and Series B Preferred Stock.

Commitments and Contractual Obligations

Refer to "Item 8. Financial Statements and Supplementary Data — Note 15, Commitments and Contingencies" for a description of lawsuits pending against the Company.

As of December 31, 2017, our contractual obligations included our Senior Notes, interest expense on our Senior Notes, asset retirement obligations, rent expense for our corporate offices, lease of the Catarina midstream assets and other long-term lease payments. The following table summarizes our contractual obligations as of December 31, 2017 (in thousands):

	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
Senior Notes	$ —	$ —	$ 600,000	$ 1,150,000	$ 1,750,000
SN UnSub Credit Agreement	—	—	175,500	—	175,500
Second Amended and Restated Credit Agreement	—	50,000	—	—	50,000
Non-Recourse Subsidiary Term Loan	382	757	3,025	—	4,164
SR Credit Agreement	23,996	—	—	—	23,996
Interest expense[(1)]	116,938	327,563	70,438	35,218	550,157
Asset retirement obligations[(2)]	—	—	—	36,098	36,098
Office rent[(3)]	6,957	21,112	22,190	30,869	81,128
Midstream assets lease[(4)]	43,566	56,001	—	—	99,567
Transportation commitments[(5)]	104,669	203,566	158,538	274,314	741,087
Other leases[(6)]	903	1,805	1,805	451	4,964
Total	$ 297,411	$ 660,804	$ 1,031,496	$ 1,526,950	$ 3,516,661

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

(2) Amounts represent the present value of our estimate of future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See “Item 8. Financial Statements and Supplementary Data — Note 13, Asset Retirement Obligations.”

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

(4) Represents payments due with respect to firm commitment oil and natural gas volumes under the Gathering Agreement related to the Western Catarina Midstream Divestiture. As part of this sale, the Gathering Agreement represents an operating lease of the Catarina midstream assets. The firm commitment term under the Gathering Agreement commenced on October 14, 2015 and continues until October 13, 2020.

(5) See “Transportation Commitments” section below, which excludes the Gathering Agreement discussed above.

(6) Represents payments due for an acreage lease agreement for a promotional ranch managed by the Company in Kenedy County, Texas which commenced on March 1, 2014 and continues until February 28, 2024. The lease agreement includes a contractual requirement for the Company to spend a minimum of $4 million to make permanent improvements over the ten year life of the lease. The lease agreement does not specify the timing for such improvements to be made within the lease term. The Company has the right to terminate the lease obligation without penalty at any time with nine months advance written notice and payment of any accrued leasehold expenses.

Transportation Commitments

As of December 31, 2017, in our Catarina area, we have two additional contracts that require us to deliver portions of our natural gas, with delivery requirements through 2021 and 2022, respectively. Under our contract expiring in 2021, we are required to deliver approximately 63 Bcf of natural gas. Under our contract expiring in 2022, we are required to deliver approximately 201 Bcf of natural gas.

We, as the operator, on behalf of ourselves and the other working interest partners, are party to three contracts that require us to deliver portions of our natural gas, with delivery requirements through 2021, 2023, and 2033, respectively. Under the contract expiring in 2021, we are required to deliver approximately 24 Bcf of natural gas. Under the contract expiring in 2023, we are required to deliver approximately 147 Bcf of natural gas. Under the contract expiring in 2033, we are required to deliver approximately 287 Bcf of natural gas.

We, as the operator, on behalf of ourselves and the other working interest partners, are party to one contract that require us to deliver portions of our NGLs. This contract expires in 2023 and requires us to deliver approximately 15 MMBbls of NGLs.

We, as the operator, on behalf of ourselves and the other working interest partners, are party to one contract that require us to deliver portions of our oil. This contract expires in 2020 and requires us to deliver approximately 5 MMBbls of oil.

In addition, as is common in our industry, we are party to certain gathering agreements that obligate us to deliver a specified volume of production over a defined time horizon. We, as the operator, on behalf of ourselves and the other working interest partners, are party to two gathering agreements that require us to deliver variable monthly quantities through 2034. Gross volumes under these contracts peak at approximately 63,000 Bbl per day (approximately 14,800 Bbl per day net) of crude oil and condensate in 2020 and 430,000 Mcf per day (approximately 101,400 Mcf per day net) of natural gas in 2022, and then decrease annually thereafter through the end of the contracts.

Development Commitments

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 period on a well for well basis. The lease also created a customary security interest in the production therefrom in order to secure royalty payments to the lessor and other lease obligations. Our current capital budget and plans include the drilling of at least the minimum number of wells required to maintain access to such undeveloped acreage.

In the 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 our 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. 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.

Off-Balance Sheet Arrangements

As of December 31, 2017, we did not have any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements that have been prepared in accordance with U.S. GAAP. The preparation of these consolidated financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in “Item 8. Financial Statements and Supplementary Data — Note 2, Basis of Presentation and Summary of Significant Accounting Policies.” When we prepare our financial statements, we review our estimates, including those related to revenue from the sale of oil, natural gas and NGLs, reserves of oil, natural gas and NGLs, fair value of derivative instruments, abandonment liabilities, income taxes, commitments and contingencies, depreciation, and depletion and amortization. Our estimates are based on historical experience and various assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements.

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. Proceeds from the sale or disposition of oil and natural gas properties are applied to reduce net capitalized costs unless the sale or disposition causes a significant change in the relationship between costs and the estimated quantities of proved reserves.

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. 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. The amortizable base includes, where significant, dismantlement, restoration and abandonment costs, net of estimated salvage value.

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. These judgments may have a significant impact on the calculation of depletion expense. At December 31, 2017, a 10% positive revision to proved reserves would decrease the depletion rate by approximately \$0.61 per Boe and a 10% negative revision to proved reserves would increase the depletion rate by approximately \$0.74 per Boe. 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 depreciation, depletion and amortization 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. Net capitalized costs of proved oil and natural gas properties are compared to estimated undiscounted future net cash flows using management's expectations of future oil and natural gas prices. 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. 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 are expected to impact the realizable price. We did not record a proved property impairment during the year ended December 31, 2017. During the year ended December 31, 2016, we recorded a proved property impairment of \$3.7 million due to the decline of oil and natural gas prices during the first half of the year. We recorded impairment of \$700.3 million to our proved oil and natural gas property impairment due to the significant decline in oil and natural gas prices during the year ended December 31, 2015. The impact of lower commodity prices adversely affecting proved reserve values primarily contributed to the proved property impairment. Changes in production rates, levels of reserves, future development costs, and other factors will determine 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. Considerable judgment is necessary in determining when unproved properties become impaired. We recorded impairment of \$39.6 million to our unproved oil and natural gas properties for the year ended

December 31, 2017 due to a write-down of our TMS acreage to fair value. We recorded impairment of $43.6 million and $23.7 million to our unproved oil and natural gas properties due to acreage abandonment from changes in development plan for the years ended December 31, 2016 and December 31, 2015, respectively.

Oil and Natural Gas Reserves

The Company's most significant estimates relate to its proved reserves of oil, natural gas and NGLs. The estimates of reserves of oil, natural gas and NGLs as of December 31, 2017, 2016 and 2015 are based on reports prepared by a third party engineering firm, Ryder Scott.

Estimates of proved reserves are based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Ryder Scott has historically prepared a reserve and economic evaluation of the Company's properties, utilizing information provided to it by management and other information available, including information from the operators of the property.

The standards of the FASB and rules of the SEC permit the use of new technologies to determine proved reserve estimates if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volume estimates. These rules allow, but do not require, companies to disclose their probable and possible reserves to investors in documents filed with the SEC.

In addition, the disclosure guidelines require companies to report oil and natural gas reserves using an average price based upon the prior 12-month first-day-of-the-month price rather than a period-end price.

Reserves and their relation to estimated future net cash flows impact the depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. The reserve estimates and the projected cash flows derived from these reserve estimates are prepared in accordance with SEC guidelines. The independent engineering firm noted above adheres to these guidelines when preparing their reserve reports. The accuracy of the reserve estimates is a function of many factors including the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered. Additionally, with other factors held constant, if the commodity prices used in our reserve report as of December 31, 2017 had decreased by 10%, then the standardized measure of our estimated proved reserves as of that date would have decreased by approximately $511.8 million, from approximately $1,886.1 million to approximately $1,374.3 million.

Asset Retirement Obligations

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

Income Taxes

The Company accounts for income taxes using the asset and liability method. Deferred tax assets and liabilities arise from the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary difference and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Valuation allowances are established when necessary to reduce the deferred tax asset to the amount more likely than not to be recovered.

Additionally, the Company is required to determine whether it is more likely than not (a likelihood of more than 50%) that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position in order to record any financial statement benefit. If that step is satisfied, then the Company must measure the tax position to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that has greater than a 50% likelihood of being realized upon ultimate settlement. Any interest or penalties would be recognized as a component of income tax expense.

The Company applies significant judgment in evaluating its tax positions and estimating its provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact the Company's financial position, results of operations and cash flows. The Company does not have any material uncertain tax positions during the years ended December 31, 2017, 2016 or 2015.

Stock-Based Compensation

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 expense 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 and phantom 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.

Revenue Recognition

Sales of oil, natural gas and NGLs are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred, and collectability of the revenue is probable. Delivery occurs and title is transferred when production has been delivered to a pipeline, railcar or truck, or a tanker lifting has occurred. The entitlement method of accounting is used for the sale of oil, natural gas and NGLs. Oil and natural gas imbalances are generated on properties for which two or more owners have the right to take production "in-kind" and, in doing so, take more or less than their respective entitled percentage.

Derivative Instruments

At times we may utilize derivative instruments to manage our exposure to fluctuations in the underlying commodity prices for the products sold by us. The carrying amount of derivative assets and liabilities is reported on the balance sheet at the estimated fair value of the derivative instruments. These derivative transactions are not designated as cash flow hedges. Accordingly, these derivative contracts are marked-to-market and any changes in the estimated value of derivative contracts held at the balance sheet date are recognized in the statement of operations as net gains (losses) on commodity derivatives.

Item 7A. ***Quantitative and Qualitative Disclosures about Market Risk***

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

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

Commodity Price Risk

Our 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.

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 amended and restated credit facility, the SN UnSub Credit Agreement and the terms of SN Unsub's organizational documents, or were governed by our prior revolving credit facility, 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 our prior revolving credit facility or the SN UnSub Credit Agreement, or (y) counterparties designated as secured with and under our amended and restated credit facility 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 our amended and restated credit facility 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. In connection with the closing of the Comanche Acquisition, we hedged a portion of projected future production attributable to the SN Comanche Assets, using hedge transactions that are consistent with our current hedging strategy. Please refer to "Item 8. Financial Statements and Supplementary Data — Note 11, Derivative Instruments" for a description of all of our derivatives covering anticipated future production as of December 31, 2017.

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 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 December 31, 2017, the fair value of our commodity derivative contracts was a net liability of approximately $55.8 million. A 10% increase in the oil and natural gas index prices above the December 31, 2017 prices would result in a decrease in the fair value of our commodity derivative contracts of $63.4 million; conversely, a 10% decrease in the oil and natural gas index prices would result in an increase of $62.6 million. As of February 23, 2018, we have commodity derivative contracts in place covering approximately 72% and 110% the mid-point of our production of oil and natural gas projections, respectively, for 2018.

Interest Rate Risk

At the Company's election, borrowings under our prior revolving credit facility, our amended and restated credit facility 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 December 31, 2017, there were $50 million in borrowings outstanding under our prior revolving credit facility and $175.5 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 December 31, 2017. 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 December 31, 2017. On February 14, 2018, we issued $500 million in aggregate principal amount of 7.25% Senior Secured Notes which bear interest at a fixed rate of 7.25% with an expected maturity date of February 15, 2023, subject to certain conditions.

Our Non-Recourse Subsidiary Term Loan bears a fixed interest rate of 4.59% with an expected maturity date of August 31, 2022, and we had approximately $4.2 million outstanding as of December 31, 2017.

The credit facility which we assumed, through a non-recourse subsidiary, when we acquired the equity in Sanchez Resources, in that same subsidiary, 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 December 31, 2017, there was approximately $24 million in borrowings past due and owing and no outstanding availability to borrow additional funds under that credit facility.

As of December 31, 2017, 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 our amended and restated credit facility, 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 8. ***Financial Statements and Supplementary Data***

The information required by this Item is included in this report as set forth in the "Index to Consolidated Financial Statements" beginning on page F-96 of this Annual Report on Form 10-K and is incorporated by reference herein.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that 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 and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective at December 31, 2017 at the reasonable assurance level.

Management's Annual Report on Internal Control Over Financial Reporting and Attestation Report of the Registered Public Accounting Firm

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Exchange Act). Even an effective system of internal control over financial reporting, no matter how well designed, has inherent limitations, including the possibility of human error, circumvention of controls or overriding of controls and, therefore, can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of a system of internal control over financial reporting in future periods can change as conditions change. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2017. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control—Integrated Framework (2013). Based on this assessment and such criteria, our management concluded that our internal control over financial reporting was effective as of December 31, 2017.

KPMG, an independent registered public accounting firm, has issued its report on the effectiveness of the Company's internal control over financial reporting at December 31, 2017. The report from KPMG is included in this Item 8 under the heading "Report of Independent Registered Public Accounting Firm."

Report of Independent Registered Public Accounting Firm

Please see Report of Independent Public Accounting Firm under "Item 8. Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

Changes in Internal Control Over Financial Reporting

In the fourth quarter of 2017, we added and modified certain internal control processes as a result of changing our method of accounting for oil and gas exploration and development activities from the full cost method to the successful efforts method. There were no other changes in our internal control over financial reporting during the fourth quarter of 2017 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

Information regarding our directors, executive officers and certain corporate governance items will be included in an amendment to this Form 10-K or in the proxy statement for the 2018 annual meeting of stockholders, in either case, to be filed within 120 days after December 31, 2017, and is incorporated by reference to this report.

Item 11. ***Executive Compensation***

Information regarding executive compensation will be included in an amendment to this Form 10-K or in the proxy statement for the 2018 annual meeting of stockholders and is incorporated by reference to this report.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

Information regarding beneficial ownership and management and related stockholder matters will be included in an amendment to this Form 10-K or in the proxy statement for the 2018 annual meeting of stockholders and is incorporated by reference to this report.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

Information regarding certain relationships and related transactions and director independence will be included in an amendment to this Form 10-K or in the proxy statement for the 2018 annual meeting of stockholders and is incorporated by reference to this report.

Item 14. ***Principal Accountant Fees and Services***

Information regarding principal accounting fees and services will be included in an amendment to this Form 10-K or in the proxy statement for the 2018 annual meeting of stockholders and is incorporated by reference to this report.

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 Annual Report on Form 10-K. The definitions "analogous reservoir," "development costs," "development project," "development well," "economically producible," "exploratory well," "field," "possible reserves," "probable reserves," "production costs," "proved area," "reservoir," "resources," and "unproved properties" have been excerpted 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.

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**:** In accordance with Rule 4-10(a)(11) of Regulation S-X under the Exchange Act, 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.

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.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

a. The following documents are filed as a part of this Annual Report on Form 10-K or incorporated herein by reference:

(1) Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

(2) Financial Statement Schedules:

None.

(3) Exhibits:

The exhibits required by Item 601 of Regulation S-K are listed in subparagraph (b) below.

b. The following exhibits are filed or furnished with this Annual Report on Form 10-K or incorporated by reference:

Exhibit No.	Description of Exhibit
2.1**	Purchase and Sale Agreement, dated as of May 21, 2014, by and among SWEPI LP, Shell Gulf of Mexico Inc., as sellers, and Sanchez Energy Corporation, as buyer (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K on May 22, 2014, and incorporated herein by reference).
2.2**	Purchase and Sale Agreement, dated as of March 31, 2015, by and among SEP Holdings III, LLC, SEP Holdings IV, LLC and Sanchez Production Partners LP (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K on April 1, 2015, and incorporated herein by reference).
2.3**	Purchase and Sale Agreement, dated as of September 25, 2015, by and among Sanchez Energy Corporation, SN Catarina, LLC and Sanchez Production Partners LP (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K on September 29, 2015, and incorporated herein by reference).
2.4**	Purchase and Sale Agreement, dated as of July 5, 2016, by and among Sanchez Energy Corporation, SN Midstream, LLC and Sanchez Production Partners LP (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K on July 6, 2016, and incorporated herein by reference).
2.5**	Purchase and Sale Agreement, dated as of October 6, 2016, by and among Sanchez Energy Corporation, SN Midstream, LLC and Sanchez Production Partners LP (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K on October 7, 2016, and incorporated herein by reference).
2.6**	Purchase and Sale Agreement, dated as of October 6, 2016, by and among SN Cotulla Assets, LLC, SN Palmetto, LLC, SEP Holdings IV, LLC and Sanchez Production Partners LP (filed as Exhibit 2.2 to the Company's Current Report on Form 8-K on October 7, 2016, and incorporated herein by reference).
2.7**	Purchase and Sale Agreement, dated as of October 6, 2016, by and among Sanchez Energy Corporation, SN Terminal, LLC and Sanchez Production Partners LP (filed as Exhibit 2.3 to the Company's Current Report on Form 8-K on October 7, 2016, and incorporated herein by reference).
2.8**	Purchase and Sale Agreement, dated as of October 24, 2016, by and among SN Cotulla Assets, LLC, Carrizo (Eagle Ford) LLC, Carrizo Oil & Gas, Inc., and for the limited purposes set forth therein, Sanchez Energy Corporation (filed as Exhibit 2.1 on the Company's Current Report on Form 8-K on January 13, 2017, and incorporated herein by reference).

Exhibit No.	Description of Exhibit
2.9**	Purchase and Sale Agreement, dated as of January 12, 2017, by and among Anadarko E&P Onshore LLC, Kerr-McGee Oil & Gas Onshore LP, SN EF Maverick, LLC, SN EF UnSub, LP, Aguila Production, LLC, and solely for the purposes of Section 15.22 and Schedule 13.4(a), Sanchez Energy Corporation (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K on January 17, 2017, and incorporated herein by reference).
2.10**	Purchase and Sale Agreement, dated as of August 17, 2017, by and between SN Cotulla Assets, LLC and Vitruvian Exploration IV, LLC. (filed as Exhibit 2.1 to the Company's Quarterly Report on Form 10-Q on November 6, 2017, and incorporated herein by reference).
3.2	Restated Certificate of Incorporation of Sanchez Energy Corporation, effective as of May 28, 2013 (filed as Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q on November 8, 2013, and incorporated herein by reference).
3.3	Certificate of Designations of Series C Junior Participating Preferred Stock of Sanchez Energy Corporation (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on July 29, 2015, and incorporated herein by reference).
3.4	Amended and Restated Bylaws dated as of December 13, 2011 (filed as Exhibit 3.2 to the Company's Current Report on Form 8-K on December 19, 2011, and incorporated herein by reference).
4.1	Form of Common Stock Certificate (filed as Exhibit 4.1 to Amendment No. 3 to the Company's Registration Statement on Form S-1 (File. No. 333-176613) on November 25, 2011, and incorporated herein by reference).
4.2	Indenture, dated as of June 13, 2013, by and among Sanchez Energy Corporation, the subsidiary guarantors named therein and U.S. Bank National Association as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8- K on June 14, 2013 and incorporated herein by reference).
4.3	First Supplemental Indenture, dated as of September 11, 2013, by and among Sanchez Energy Corporation, SN TMS, LLC, the existing guarantors and U.S. Bank National Association as trustee (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K on September 19, 2013 and incorporated herein by reference).
4.6	Registration Rights Agreement, dated as of December 19, 2011, by and between Sanchez Energy Corporation and Sanchez Energy Partners I, LP (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference).
4.7	Second Supplemental Indenture, dated as of June 2, 2014, by and among Sanchez Energy Corporation, SN Catarina, LLC, the existing guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.6 to the Company's Registration Statement on Form S-4 (File No. 333-196660)on June 11, 2014, and incorporated herein by reference).
4.8	Indenture, dated as of June 27, 2014, by and among Sanchez Energy Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on July 2, 2014, and incorporated herein by reference).
4.11	Rights Plan dated as of July 28, 2015, by and between Sanchez Energy Corporation and Continental Stock Transfer & Trust Company, as Rights Agent (including the form of Certificate of Designations of Series C Junior Participating Preferred Stock attached thereto as Exhibit A, the form of Right Certificate attached thereto as Exhibit B and the Summary of Rights attached thereto as Exhibit C) (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on July 29, 2015, and incorporated herein by reference).

Exhibit No.	Description of Exhibit
4.12	Instrument of Resignation, Appointment and Acceptance (7.75% Senior Notes), dated as of May 20, 2016, by and among Sanchez Energy Corporation, Delaware Trust Company and U.S. Bank National Association (filed as Exhibit 4.1 to the Company’s Quarterly Report on Form 10-Q on August 8, 2016, and incorporated herein by reference).
4.13	Instrument of Resignation, Appointment and Acceptance (6.125% Senior Notes), dated as of May 20, 2016, by and among Sanchez Energy Corporation, Delaware Trust Company and U.S. Bank National Association (filed as Exhibit 4.2 to the Company’s Quarterly Report on Form 10-Q on August 8, 2016, and incorporated herein by reference).
4.14	Warrant Agreement, dated as of March 1, 2017, by and between Sanchez Energy Corporation and Gavilan Resources Holdings—A, LLC (filed as Exhibit 4.1 to the Company’s Current Report on Form 8-K on March 6, 2017, and incorporated herein by reference).
4.15	Warrant Agreement, dated as of March 1, 2017, by and between Sanchez Energy Corporation and Gavilan Resources Holdings—B, LLC (filed as Exhibit 4.2 to the Company’s Current Report on Form 8-K on March 6, 2017, and incorporated herein by reference).
4.16	Warrant Agreement, dated as of March 1, 2017, by and between Sanchez Energy Corporation and Gavilan Resources Holdings—C, LLC (filed as Exhibit 4.3 to the Company’s Current Report on Form 8-K on March 6, 2017, and incorporated herein by reference).
4.17	Warrant Agreement, dated as of March 1, 2017, by and between Sanchez Energy Corporation and GSO Capital Opportunities Fund III LP, GSO Energy Select Opportunities Fund LP, GSO Energy Partners—A LP, GSO Energy Partners—B LP, GSO Energy Partners—C LP, GSO Energy Partners—C II LP, GSO Energy Partners—D LP, GSO Credit Alpha Fund LP, GSO Harrington Credit Alpha Fund (Cayman) L.P., and GSO Capital Solutions Funds II LP (filed as Exhibit 4.4 to the Company’s Current Report on Form 8-K on March 6, 2017, and incorporated herein by reference).
4.18	Warrant Agreement, dated as of March 1, 2017, by and between Sanchez Energy Corporation and Intrepid Private Equity V-A, LLC (filed as Exhibit 4.5 to the Company’s Current Report on Form 8-K on March 6, 2017, and incorporated herein by reference).
4.19	Amendment No. 1, dated as of March 1, 2017, to Rights Agreement, dated as of July 28, 2015, by and between Sanchez Energy Corporation and Continental Stock Transfer & Trust Company, as rights agent (incorporated by reference from Exhibit 4.2 to the Company’s Form 8-A/A filed with the SEC on March 3, 2017)
4.20	Registration Rights Agreement, dated March 1, 2017, by and among Sanchez Energy Corporation and the GSO Funds, as defined therein (incorporated by reference from Exhibit 4.1 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).
4.21	Registration Rights Agreement, dated March 1, 2017, by and between Sanchez Energy Corporation and Intrepid Private Equity V-A, LLC (incorporated by reference from Exhibit 4.2 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).
4.22	Registration Rights Agreement, dated March 1, 2017, by and among Sanchez Energy Corporation, Gavilan Resources Holdings – A, LLC, Gavilan Resources Holdings – B, LLC and Gavilan Resources Holdings – C, LLC (incorporated by reference from Exhibit 4.3 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).

Exhibit No.	Description of Exhibit
4.23	Standstill and Voting Agreement, dated February 6, 2017, by and among Sanchez Energy Corporation and the GSO Funds, as defined therein (incorporated by reference from Exhibit 4.4 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).
4.24	Amendment No. 1 to Standstill and Voting Agreement, dated March 1, 2017, by and among Sanchez Energy Corporation and the GSO Funds, as defined therein (incorporated by reference from Exhibit 4.5 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).
4.25	Standstill and Voting Agreement, dated March 1, 2017, by and among Sanchez Energy Corporation, Blackstone Capital Partners VII L.P. and Blackstone Energy Partners II L.P. (incorporated by reference from Exhibit 4.6 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).
4.26	First Supplemental Indenture (6.125% Senior Notes due 2023), dated March 7, 2017, by and among Sanchez Energy Corporation, SN EF Maverick, LLC, Rockin L Ranch Company, LLC, the existing guarantors and Delaware Trust Company as trustee (incorporated by reference from Exhibit 4.13 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).
4.27	Third Supplemental Indenture (7.75% Senior Notes due 2021), dated March 7, 2017, by and among Sanchez Energy Corporation, SN EF Maverick, LLC, Rockin L Ranch Company, LLC, the existing guarantors and Delaware Trust Company, as trustee (incorporated by reference from Exhibit 4.14 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).
4.28	Indenture (7.25% Senior Secured First Lien Notes due 2023), dated February 14, 2018, by and among Sanchez Energy Corporation, the guarantors party thereto, Delaware Trust Company, as trustee, and Royal Bank of Canada, as collateral trustee (incorporated by reference from Exhibit 4.1 to the Company’s Current Report on Form 8-K on February 20, 2018, and incorporated herein by reference).
10.1	Services Agreement, dated as of December 19, 2011, by and between Sanchez Oil & Gas Corporation and Sanchez Energy Corporation (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference).
10.2	Geophysical Seismic Data Use License Agreement, dated as of December 19, 2011, by and among Sanchez Oil & Gas Corporation, Sanchez Energy Corporation, SEP Holdings III, LLC and SN Marquis LLC (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference).
10.3*	Indemnification Agreement, dated as of December 19, 2011, by and between Sanchez Energy Corporation and Antonio R. Sanchez, III (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference).
10.4*	Indemnification Agreement, dated as of December 19, 2011, by and between Sanchez Energy Corporation and Michael G. Long (filed as Exhibit 10.5 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference).
10.5*	Indemnification Agreement, dated as of December 19, 2011, by and between Sanchez Energy Corporation and Gilbert A. Garcia (filed as Exhibit 10.6 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference).
10.6*	Form of Restricted Stock Agreement for Employees (filed as Exhibit 10.1 to the Company's Registration Statement on Form S-8 (File No. 333-178920) on January 6, 2012, and incorporated herein by reference).
10.7*	Form of Restricted Stock Agreement for Non-employee Directors (filed as Exhibit 10.2 to the Company's Registration Statement on Form S-8 (File No. 333-178920) on January 6, 2012, and incorporated herein by reference).

Exhibit No.	Description of Exhibit
10.8*	Form of Restricted Stock Agreement for Antonio R. Sanchez, III (filed as Exhibit 10.3 to the Company's Registration Statement on Form S-8 (File No. 333-178920) on January 6, 2012, and incorporated herein by reference).
10.9*	Indemnification Agreement, dated as of March 9, 2012, by and between Sanchez Energy Corporation and Greg Colvin (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on March 14, 2012, and incorporated herein by reference).
10.10*	Indemnification Agreement, dated as of March 9, 2012, by and between Sanchez Energy Corporation and Kirsten A. Hink (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on March 14, 2012, and incorporated herein by reference).
10.11*	Indemnification Agreement, dated as of November 27, 2012, by and between Sanchez Energy Corporation and A.R. Sanchez, Jr. (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on December 3, 2012, and incorporated herein by reference).
10.12*	Indemnification Agreement, dated as of November 27, 2012, by and between Sanchez Energy Corporation and Alan G. Jackson (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on December 3, 2012, and incorporated herein by reference).
10.13*	Indemnification Agreement, dated as of March 4, 2014, by and between Sanchez Energy Corporation and Christopher Heinson (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on March 6, 2014, and incorporated herein by reference).
10.15	Second Amended and Restated Credit Agreement, dated as of June 30, 2014, by and among Sanchez Energy Corporation, as borrower, SEP Holdings III, LLC, SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC and SN Catarina, LLC, as loan parties, Royal Bank of Canada, as administrative agent, Capital One, National Association, as syndication agent, Compass Bank, SunTrust Bank as co-documentation agents, RBC Capital Markets, LLC as sole lead arranger and sole book runner, and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on July 2, 2014, and incorporated herein by reference).
10.17	First Amendment to Second Amended and Restated Credit Agreement, dated as of September 9, 2014, by and among Sanchez Energy Corporation, as borrower, SEP Holdings III, LLC, SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC and SN Catarina, LLC, as loan parties, Royal Bank of Canada, as administrative agent, Capital One, National Association, as syndication agent, Compass Bank, SunTrust Bank as co-documentation agents, RBC Capital Markets, LLC as sole lead arranger and sole book runner, and the lenders party thereto (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on September 15, 2014, and incorporated herein by reference).
10.18*	Indemnification Agreement, dated as of November 4, 2014, by and between Sanchez Energy Corporation and Sean Maher (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on November 6, 2014, and incorporated herein by reference).
10.19	Second Amendment to Second Amended and Restated Credit Agreement, dated as of March 31, 2015, by and among Sanchez Energy Corporation, as borrower, SN Marquis LLC, SN Cotulla Assets LLC, SN Operating LLC, SN TMS, LLC, and SN Catarina LLC, as guarantors, Royal Bank of Canada, as administrative agent, and the other agents and lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 1, 2015, and incorporated herein by reference).
10.20*	Indemnification Agreement, dated as of May 5, 2015, by and between Sanchez Energy Corporation and Thomas Brian Carney (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on May 8, 2015, and incorporated herein by reference).

Exhibit No.	Description of Exhibit
10.21*	Indemnification Agreement, dated as of May 5, 2015, by and between Sanchez Energy Corporation and G. Gleeson Van Riet (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on May 8, 2015, and incorporated herein by reference).
10.22*	Sanchez Energy Corporation Third Amended and Restated 2011 Long Term Incentive Plan (filed as Exhibit 99.1 to the Company's Current Report on Form 8-K on May 26, 2016, and incorporated herein by reference).
10.23*	Indemnification Agreement, dated as of October 1, 2015, by and between Sanchez Energy Corporation and Eduardo Sanchez (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on October 6, 2015, and incorporated herein by reference).
10.24	Third Amendment to Second Amended and Restated Credit Agreement, dated as of July 20, 2015, by and among Sanchez Energy Corporation, as borrower, SN Marquis LLC, SN Cotulla Assets LLC, SN Operating LLC, SN TMS, LLC, and SN Catarina LLC, as guarantors, Royal Bank of Canada, as administrative agent, and the other agents and lenders party thereto (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on November 8, 2013, and incorporated herein by reference).
10.25	Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of September 29, 2015, by and among Sanchez Energy Corporation, as borrower, SN Marquis LLC, SN Cotulla Assets LLC, SN Operating LLC, SN TMS, LLC, and SN Catarina LLC, as guarantors, Royal Bank of Canada, as administrative agent, and the other agents and lenders party thereto (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q on November 8, 2013, and incorporated herein by reference).
10.26	Fifth Amendment to Second Amended and Restated Credit Agreement, dated as of October 30, 2015, by and among Sanchez Energy Corporation, as borrower, SEP Holdings III, LLC, SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC, and SN Catarina, LLC, as guarantors, Royal Bank of Canada, as administrative agent, and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on November 4, 2015, and incorporated herein by reference).
10.27	Sixth Amendment to Second Amended and Restated Credit Agreement, dated as of January 22, 2016, by and among Sanchez Energy Corporation, as borrower, SEP Holdings III, LLC, SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC, and SN Catarina, LLC, as guarantors, Royal Bank of Canada, as administrative agent, and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 25, 2016, and incorporated herein by reference).
10.28	Seventh Amendment to Second Amended and Restated Credit Agreement, dated as of March 18, 2016, by and among Sanchez Energy Corporation, as borrower, SEP Holdings III, LLC, SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC, and SN Catarina, LLC, as guarantors, Royal Bank of Canada, as administrative agent, and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on March 21, 2016, and incorporated herein by reference).
10.29	Eighth Amendment to Second Amended and Restated Credit Agreement, dated as of April 18, 2017, by and among Sanchez Energy Corporation, as borrower, SN Palmetto, LLC (f/k/a SEP Holdings III, LLC), SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC, SN Catarina, LLC, SN EF Maverick, LLC, and Rockin L Ranch Company, LLC, as guarantors, Royal Bank of Canada, as administrative agent, and the lenders party thereto (filed as exhibit 10.1 to the Company's Current Report on Form 8-K on April 24, 2017, and incorporated herein by reference).

Exhibit No.	Description of Exhibit
10.30	Ninth Amendment to Second Amended and Restated Credit Agreement, dated as of July 1, 2017, by and among Sanchez Energy Corporation, as borrower, SN Palmetto, LLC (f/k/a SEP Holdings III, LLC), SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC, SN Catarina, LLC, SN EF Maverick, LLC, and Rockin L Ranch Company, LLC, as guarantors, Royal Bank of Canada, as administrative agent, and the lenders party thereto. (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on November 6, 2017, and incorporated herein by reference).
10.31	Letter Agreement, dated as of December 9, 2016, by and among Royal Bank of Canada, as administrative agent under the Second Amended and Restated Credit Agreement, as amended, Sanchez Energy Corporation, as borrower and the other parties thereto (filed as Exhibit 10.29 to the Company's Annual Report on Form 10-K on February 27, 2017, and incorporated herein by reference).
10.32*	Indemnification Agreement, dated as of December 14, 2015, by and between Sanchez Energy Corporation and Gregory B. Kopel (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on December 16, 2015, and incorporated herein by reference).
10.33*	Indemnification Agreement, dated as of March 8, 2016, by and between Sanchez Energy Corporation and Garrick Hill (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on March 8, 2016, and incorporated herein by reference).
10.34*	Form of Restricted Stock Award Agreement for Employees (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 21, 2016, and incorporated herein by reference).
10.35*	Form of Performance Accelerated Restricted Stock Agreement for Employees (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 21, 2016, and incorporated herein by reference).
10.36*	Form of Phantom Stock Agreement for Employees (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 21, 2016, and incorporated herein by reference).
10.37*	Form of Performance Accelerated Phantom Stock Agreement for Employees (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 21, 2016, and incorporated herein by reference).
10.38*	Indemnification Agreement, dated as of August 2, 2016, by and between Sanchez Energy Corporation and Robert Nelson (filed as Exhibit 10.1 on the Company's Current Report on Form 8-K on August 3, 2016, and incorporated herein by reference).
10.39*	Indemnification Agreement, dated as of October 10, 2016, by and between Sanchez Energy Corporation and Howard Thill (filed as Exhibit 10.1 on the Company's Current Report on Form 8-K on October 12, 2016, and incorporated herein by reference).
10.40*	Restricted Stock Agreement, dated as of October 10, 2016, by and between Sanchez Energy Corporation and Howard Thill (filed as Exhibit 10.2 on the Company's Current Report on Form 8-K on October 12, 2016, and incorporated herein by reference).
10.41*	Phantom Stock Agreement, dated as of October 10, 2016, by and between Sanchez Energy Corporation and Howard Thill (filed as Exhibit 10.3 on the Company's Current Report on Form 8-K on October 12, 2016, and incorporated herein by reference).
10.42*	Indemnification Agreement, dated as of November 3, 2016, by and between Sanchez Energy Corporation and Patricio D. Sanchez (filed as Exhibit 10.1 on the Company's Current Report on Form 8-K on November 9, 2016, and incorporated herein by reference).

Exhibit No.	Description of Exhibit
10.43**	Securities Purchase Agreement, dated as of January 12, 2017, by and among Sanchez Energy Corporation, SN UR Holdings, LLC, SN EF UnSub Holdings, LLC, SN EF UnSub, LP, SN EF UnSub GP, LLC, GSO ST Holdings Associates LLC, and GSO ST Holdings LP (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 17, 2017, and incorporated herein by reference).
10.44**	Interim Investors Agreement, dated as of January 12, 2017, by and among Sanchez Energy Corporation, SN EF Maverick, LLC, SN EF UnSub, LP, Aguila Production, LLC, Aguila Production HoldCo, LLC, Blackstone Capital Partners VII L.P., and Blackstone Energy Partners II L.P. (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on January 12, 2017, and incorporated herein by reference).
10.45	Underwriting Agreement, dated January 31, 2017, by and between Sanchez Energy Corporation and J.P. Morgan Securities LLC, as representative of the several underwriters named therein (filed as Exhibit 1.1 to the Company's Current Report on Form 8-K on February 2, 2017, and incorporated herein by reference).
10.46	Amended and Restated Agreement of Limited Partnership of SN EF UnSub, LP, dated March 1, 2017 (incorporated by reference from Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).
10.47	Amended and Restated Limited Liability Company Agreement of SN EF UnSub GP, LLC, dated March 1, 2017 (incorporated by reference from Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).
10.48	Amended and Restated Limited Liability Company Agreement of Gavilan Resources HoldCo, LLC, dated March 1, 2017 (incorporated by reference from Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).
10.49	First Lien Credit Agreement, dated March 1, 2017, by and among SN EF UnSub, LP, JPMorgan Chase Bank, N.A., Citigroup Global Markets Inc., Capital One, National Association, RBC Capital Markets LLC, BMO Harris Bank, NA, ING Capital LLC and SunTrust Robinson Humphrey, Inc. (incorporated by reference from Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).
10.50	Shareholders Agreement, dated March 1, 2017, by and between Gavilan Resources HoldCo, LLC and Sanchez Energy Corporation (incorporated by reference from Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).
10.51	Amended and Restated Securities Purchase Agreement, dated February 28, 2017, by and among Sanchez Energy Corporation, SN UR Holdings, LLC, SN EF UnSub Holdings, LLC, SN EF UnSub, LP, SN EF UnSub GP, LLC, Intrepid Private Equity V-A, LLC, GSO ST Holdings Associates LLC and GSO ST Holdings LP. (incorporated by reference from Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).
10.52	Interim Investors Agreement, dated January 12, 2017, by and among Sanchez Energy Corporation, SN EF Maverick, LLC, SN EF UnSub, LP, Aguila Production, LLC, Aguila Production HoldCo, LLC, Blackstone Capital Partners VII L.P. and Blackstone Energy Partners II L.P. (incorporated by reference from Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).
10.53	Joint Development Agreement, dated March 1, 2017, by and among Gavilan Resources, LLC, SN EF Maverick, LLC, SN EF UnSub, LP and, solely for the purposes stated therein, Sanchez Energy Corporation (incorporated by reference from Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).
10.54	Management Services Agreement, dated March 1, 2017, by and between Sanchez Oil & Gas Corporation and SN EF UnSub, LP. (incorporated by reference from Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).

Exhibit No.	Description of Exhibit
10.55	Management Services Agreement, dated March 1, 2017, by and among Gavilan Resources HoldCo, LLC, SN Comanche Manager, LLC and, solely for the limited purposes stated therein, SN EF Maverick, LLC (incorporated by reference from Exhibit 10.11 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).
10.56	Letter Agreement, dated as of March 1, 2017, between SN Comanche Manager, LLC and Sanchez Oil & Gas Corporation (incorporated by reference from Exhibit 10.12 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).
10.57*	Form of Performance Stock Award Agreement (incorporated by reference from Exhibit 10.13 to the Company's Quarterly Report on Form 10-Q on May 10, 2017, and incorporated herein by reference).
10.58	Equity Distribution Agreement, dated as of May 25, 2017, among Sanchez Energy Corporation, Citigroup Global Markets Inc., BMO Capital Markets Corp., Capital One Securities, Inc., RBC Capital Markets, LLC and SunTrust Robinson Humphrey, Inc. (filed as Exhibit 1.1 to the Company's Current Report on Form 8-K on May 25, 2017, and incorporated herein by reference).
10.59	Mutual Written Consent to Terminate Purchase and Sale Agreement, dated September 11, 2017, by and among Sanchez Energy Corporation, SN Terminal, LLC and Sanchez Midstream Partners LP. (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q on November 6, 2017, and incorporated herein by reference).
10.60	Purchase Agreement, dated February 7, 2018, by and among Sanchez Energy Corporation, the subsidiary guarantors named therein and Citigroup Global Markets Inc., as representative of the several initial purchasers named therein (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on February 12, 2018, and incorporated herein by reference).
10.61	Third Amended and Restated Credit Agreement dated as of February 14, 2018 among Sanchez Energy Corporation, as borrower, Royal Bank of Canada, as administrative agent and collateral agent, RBC Capital Markets, as Arranger, and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on February 20, 2018, and incorporated herein by reference).
21.1(a)	List of Subsidiaries of Sanchez Energy Corporation.
23.1(a)	Consent of KPMG LLP.
23.3(a)	Consent of Ryder Scott Company, L.P.
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.
99.1(a)	Ryder Scott Company, L.P. Summary of December 31, 2017 Reserves.
101.INS(a)	XBRL Instance Document.
101.SCH(a)	XBRL Taxonomy Extension Schema Document.
101.CAL(a)	XBRL Taxonomy Extension Calculation Linkbase Document.

Exhibit No.	Description of Exhibit
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.

** The exhibits and schedules to this agreement have been omitted form this filing pursuant to Item 601(b)(2) of Regulation S-K. The Company will furnish copies of such omitted exhibits and schedules to the SEC upon request.

Item 16. *Form 10-K Summary*

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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 February 28, 2018.

SANCHEZ ENERGY CORPORATION

By: /s/ ANTONIO R. SANCHEZ, III

Antonio R. Sanchez, III
Chief Executive Officer

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Antonio R. Sanchez, III and Howard J. Thill, and each of them, as his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite or necessary to be done in connection therewith, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated:

Signature	Title	Date
/s/ ANTONIO R. SANCHEZ, III Antonio R. Sanchez, III	Chief Executive Officer (Principal Executive Officer)	February 28, 2018
/s/ HOWARD J. THILL Howard J. Thill	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2018
/s/ KIRSTEN A. HINK Kirsten A. Hink	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 28, 2018
/s/ A. R. SANCHEZ, JR. A. R. Sanchez, Jr.	Executive Chairman of the Board of Directors	February 28, 2018
/s/ GILBERT A. GARCIA Gilbert A. Garcia	Director	February 28, 2018
/s/ GREG COLVIN Greg Colvin	Director	February 28, 2018
/s/ ALAN G. JACKSON Alan G. Jackson	Director	February 28, 2018

/s/ SEAN M. MAHER Sean M. Maher	Director	February 28, 2018
/s/ BRIAN CARNEY Brian Carney	Director	February 28, 2018
/s/ ROBERT V. NELSON, III Robert V. Nelson, III	Director	February 28, 2018

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Sanchez Energy Corporation

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
Sanchez Energy Corporation:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Sanchez Energy Corporation and subsidiaries (the Company) as of December 31, 2017 and 2016, the related consolidated statements of operations, stockholders' equity (deficit), and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 28, 2018 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Change in Accounting Principle

As discussed in Note 3 to the consolidated financial statements, the Company has elected to change its method of accounting for oil and gas exploration and development activities from full-cost method of accounting to the successful-efforts method of accounting in 2017.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

We have served as the Company's auditor since 2015.

/s/ KPMG LLP

Houston, Texas
February 28, 2018

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
Sanchez Energy Corporation:

Opinion on Internal Control Over Financial Reporting

We have audited Sanchez Energy Corporation*'s and* subsidiaries' (the Company) internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2017 and 2016, the related consolidated statements of operations, stockholders' equity (deficit), and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes (collectively, the consolidated financial statements), and our report dated February 28, 2018 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Controls Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

Houston, Texas
February 28, 2018

Sanchez Energy Corporation

Consolidated Balance Sheets

(in thousands, except share and per share amounts)

	December 31, 2017	December 31, 2016*
ASSETS		
Current assets:		
Cash and cash equivalents	$ 184,434	$ 501,917
Oil and natural gas receivables	101,396	41,077
Joint interest billings receivables	22,569	476
Accounts receivable - related entities	4,491	6,401
Fair value of derivative instruments	16,430	—
Other current assets	21,478	12,934
Total current assets	350,798	562,805
Oil and natural gas properties, on the basis of successful efforts accounting:		
Proved oil and natural gas properties	3,130,407	1,849,732
Unproved oil and natural gas properties	398,605	225,023
Total oil and natural gas properties	3,529,012	2,074,755
Less: Accumulated depreciation, depletion, amortization and impairment	(1,501,553)	(1,370,236)
Total oil and natural gas properties, net	2,027,459	704,519
Other assets:		
Fair value of derivative instruments	1,428	—
Investments (Investment in SNMP measured at fair value of $25.2 million and $26.8 million as of December 31, 2017 and 2016, respectively)	38,462	39,656
Other assets	52,488	25,231
Total assets	$ 2,470,635	$ 1,332,211
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 14,994	$ 1,076
Accounts payable - related entities	—	—
Other payables	81,970	2,251
Accrued liabilities:		
Capital expenditures	85,340	35,154
Other	84,794	82,458
Deferred premium liability	—	2,079
Fair value of derivative instruments	56,190	31,778
Short term debt	23,996	—
Other current liabilities	115,244	31,108
Total current liabilities	462,528	185,904
Long term debt, net of premium, discount and debt issuance costs	1,930,683	1,712,767
Asset retirement obligations	36,098	25,087
Fair value of derivative instruments	17,474	3,236
Other liabilities	65,480	89,199
Total liabilities	2,512,263	2,016,193
Commitments and contingencies (Note 15)		
Mezzanine equity:		
Preferred units ($1,000 liquidation preference, 500,000 units authorized; 500,000 and zero units issued and outstanding as of December 31, 2017 and December 31, 2016, respectively)	427,512	—
Stockholders' equity:		
Preferred stock ($0.01 par value, 15,000,000 shares authorized; 1,838,985 shares issued and outstanding as of December 31, 2017 and 2016 of 4.875% Convertible Perpetual Preferred Stock, Series A; 3,527,830 shares issued and outstanding as of December 31, 2017 and 2016 of 6.500% Convertible Perpetual Preferred Stock, Series B, respectively)	53	53
Common stock ($0.01 par value, 150,000,000 shares authorized; 83,984,827 and 66,622,624 shares issued and outstanding as of December 31, 2017 and 2016, respectively)	845	670
Additional paid-in capital	1,362,118	1,112,397
Accumulated deficit	(1,832,156)	(1,797,102)
Total stockholders' equity (deficit)	(469,140)	(683,982)
Total liabilities and stockholders' equity (deficit)	$ 2,470,635	$ 1,332,211

* Financial information for 2016 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 consolidated financial statements.

Sanchez Energy Corporation

Consolidated Statements of Operations

(in thousands, except per share amounts)

	Year Ended December 31,		
	2017	**2016***	**2015***
REVENUES:			
Oil sales	$ 400,045	$ 241,766	$ 307,971
Natural gas liquid sales	171,139	81,744	69,011
Natural gas sales	169,147	107,816	98,797
Total revenues	740,331	431,326	475,779
OPERATING COSTS AND EXPENSES:			
Oil and natural gas production expenses	244,461	155,660	154,672
Production and ad valorem taxes	36,615	19,633	26,870
Exploration expenses	5,755	403	1,982
Depreciation, depletion, amortization and accretion	177,078	147,485	264,379
Impairment of oil and natural gas properties	39,574	47,381	723,971
General and administrative (inclusive of non-cash stock-based compensation expense of $22,909, $24,961, and $14,831, for 2017, 2016, and 2015, respectively)	144,401	110,081	74,160
Total operating costs and expenses	647,884	480,643	1,246,034
Operating income (loss)	92,447	(49,317)	(770,255)
Other income (expense):			
Interest income	836	856	442
Other income (expense)	11,102	134	(2,605)
Gain on sale of oil and natural gas properties	81,955	85,322	—
Interest expense	(140,163)	(126,973)	(126,399)
Earnings from equity investments	779	3,466	—
Net gains (losses) on commodity derivatives	(6,100)	(53,149)	172,886
Total other income (expense)	(51,591)	(90,344)	44,324
Loss before income taxes	40,856	(139,661)	(725,931)
Income tax benefit (expense)	2,336	(1,825)	(158)
Net income (loss)	43,192	(141,486)	(726,089)
Less:			
Preferred stock dividends	(15,948)	(15,948)	(16,008)
Preferred unit dividends and distributions	(44,259)	—	—
Preferred unit amortization	(18,039)	—	—
Net income allocable to participating securities	—	—	—
Net loss attributable to common stockholders	$ (35,054)	$ (157,434)	$ (742,097)
Net loss per common share - basic and diluted	$ (0.46)	$ (2.67)	$ (12.97)
Weighted average number of shares used to calculate net loss attributable to common stockholders - basic and diluted	75,608	58,900	57,229

* Financial information for 2016 and 2015 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 consolidated financial statements.

Sanchez Energy Corporation

Consolidated Statements of Stockholders' Equity (Deficit)

(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	Equity (Deficit)
Previously reported as of December 31, 2014	1,839	$ 18	3,532	$ 35	58,581	$ 586	$ 1,064,667	$ (65,719)	$ 999,587
Effect of change in accounting principle								(831,852)	(831,852)
BALANCE, December 31, 2014 as recast*	1,839	18	3,532	35	58,581	586	1,064,667	(897,571)	167,735
Preferred stock dividends	—	—	—	—	—	—	—	(15,960)	(15,960)
Restricted stock awards, net of forfeitures	—	—	—	—	3,337	33	(33)	—	—
Exchange of preferred stock for common stock	—	—	(4)	—	10	—	48	(48)	—
Stock-based compensation	—	—	—	—	—	—	14,831	—	14,831
Net loss	—	—	—	—	—	—	—	(726,089)	(726,089)
BALANCE, December 31, 2015*	1,839	18	3,528	35	61,928	619	1,079,513	(1,639,668)	(559,483)
Preferred stock dividends	—	—	—	—	967	10	7,964	(15,948)	(7,974)
Restricted stock awards, net of forfeitures	—	—	—	—	3,728	41	(41)	—	—
Stock-based compensation	—	—	—	—	—	—	24,961	—	24,961
Net loss	—	—	—	—	—	—	—	(141,486)	(141,486)
BALANCE, December 31, 2016*	1,839	18	3,528	35	66,623	670	1,112,397	(1,797,102)	(683,982)
Issuance of warrants	—	—	—	—	—	—	58,958	—	58,958
Issuance of common shares to holders of Preferred Units	—	—	—	—	1,500	15	17,940	—	17,955
Issuance of common stock, net of offering costs of $7.8 million	—	—	—	—	11,500	115	134,748	—	134,863
Dividends on Series A and Series B Preferred Stock	—	—	—	—	2,437	24	15,924	(15,948)	—
Dividends on SN UnSub preferred units	—	—	—	—	—	—	—	(41,667)	(41,667)
Distributions - SN UnSub preferred units	—	—	—	—	—	—	—	(2,592)	(2,592)
Accretion of discount on SN UnSub preferred units	—	—	—	—	—	—	—	(18,039)	(18,039)
Restricted stock awards, net of forfeitures	—	—	—	—	1,925	21	(21)	—	—
Stock-based compensation	—	—	—	—	—	—	22,909	—	22,909
Deferred tax benefit - current period retained earnings impact	—	—	—	—	—	—	(737)	—	(737)
Net income	—	—	—	—	—	—	—	43,192	43,192
BALANCE, December 31, 2017	1,839	$ 18	3,528	$ 35	83,985	$ 845	$ 1,362,118	$ (1,832,156)	$ (469,140)

* Financial information for 2016, 2015, and 2014 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 consolidated financial statements.

Sanchez Energy Corporation

Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2017	2016*	2015*
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 43,192	$ (141,486)	$ (726,089)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	177,078	147,485	264,379
Impairment of oil and natural gas properties	39,574	47,381	723,971
Gain on sale of oil and natural gas properties	(81,955)	(85,322)	—
Stock-based and phantom unit compensation expense	40,298	37,090	14,830
Net (gains) losses on commodity derivative contracts	6,100	53,149	(172,886)
Net cash settlement received on commodity derivative contracts	17,628	122,145	131,123
Losses incurred on premiums for derivative contracts	—	24,548	(121)
Loss on embedded derivative	1,551	—	—
Cash reimbursements received for operating leasehold improvements	—	—	2,649
(Gain) loss on investments	871	(1,818)	935
Amortization of deferred gain on Western Catarina Midstream Divestiture	(23,720)	(23,720)	(4,943)
Amortization of debt issuance costs	12,647	7,840	7,529
Accretion of debt discount, net	634	633	703
Deferred taxes	(737)	—	1
(Gain) loss on inventory market adjustment	(9)	649	—
Distributions from equity investments	1,191	930	—
Earnings from equity investments	(779)	(3,466)	—
Changes in operating assets and liabilities:			
Accounts receivable	(86,604)	(9,626)	60,480
Accounts receivable - related entities	1,957	(2,704)	(3,311)
Other current assets	(15,222)	1,504	(450)
Other assets	(946)	—	—
Accounts payable	13,918	(3,108)	(25,303)
Other payables	76,304	247	(2,290)
Accrued liabilities	2,435	10,404	3,347
Other current liabilities	66,683	—	(5,166)
Other long-term liabilities	—	—	1,188
Net cash provided by operating activities	292,089	182,754	270,576
CASH FLOWS FROM INVESTING ACTIVITIES:			
Payments for oil and natural gas properties	(500,334)	(312,939)	(654,154)
Payments for other property and equipment	(18,566)	(5,394)	(8,123)
Proceeds from sale of oil and natural gas properties	162,801	179,143	427,571
Acquisition of oil and natural gas properties	(1,039,127)	—	(7,658)
Investment in SMNP	—	(25,000)	—
Purchases of investments	(74)	(36,502)	(49,985)
Sale of investments	12,500	92,458	—
Net cash used in investing activities	(1,382,800)	(108,234)	(292,349)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	373,250	60,000	—
Repayment of borrowings	(143,586)	(60,000)	—
Issuance of common stock (net of underwriting discounts of $7.8 million)	135,942	—	—
Issuance of preferred units	500,000	—	—
Issuance costs related to preferred units	(20,894)	—	—
Financing costs	(25,788)	(1,758)	(400)
Preferred dividends paid	—	(3,987)	(15,960)
Cash paid to tax authority for employee stock-based compensation awards	(1,437)	(1,906)	(533)
Preferred unit distribution	(44,259)	—	—
Net cash provided by (used in) financing activities	773,228	(7,651)	(16,893)
Increase (decrease) in cash and cash equivalents	(317,483)	66,869	(38,666)
Cash and cash equivalents, beginning of period	501,917	435,048	473,714
Cash and cash equivalents, end of period	$ 184,434	$ 501,917	$ 435,048
NON-CASH INVESTING AND FINANCING ACTIVITIES:			
Change in asset retirement obligations	$ 8,376	$ (2,895)	$ (1,877)
Change in accrued capital expenditures	50,613	(16,829)	(110,744)
Debt assumed in exchange for equity interest in SR	23,996	—	—
SUPPLEMENTAL DISCLOSURE:			
Cash paid for taxes	$ —	$ 1,996	$ 158
Cash paid for interest	$ 126,516	$ 118,498	$ 121,644

* Financial information for 2016 and 2015 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 consolidated financial statements.

Sanchez Energy Corporation

Notes to the Consolidated Financial Statements

Note 1. Organization and Business

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 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 December 31, 2017, we have assembled approximately 487,000 gross leasehold acres (285,000 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.

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

Basis of Presentation

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP").

Recent Accounting Pronouncements

In August 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2017-12 "Derivatives and Hedging (Topic 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. Early adoption is permitted, and 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 Accounting Standards Update ("ASU") 2017-01 "Business Combinations (Topic 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 effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2017. Early adoption is permitted, and the Company is currently in the process of evaluating the impact of adoption of this guidance on its consolidated financial statements.

In November 2016, the FASB issued ASU 2016-18 "Statement of Cash Flows (Topic 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 effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2017. The Company does not anticipate that ASU 2016-18 will have a material effect on its consolidated and condensed financial statements and related disclosures.

In October 2016, the FASB issued ASU 2016-16 "Income Taxes (Topic 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 will be effective beginning with the first quarter of 2018. The Company is currently in the process of evaluating the impact of adoption of this guidance on its consolidated financial statements.

In August 2016, the FASB issued ASU No. 2016-15 "Statement of Cash Flows: 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 effective for financial statements issued for annual periods beginning after December 15, 2017, including interim periods within those annual periods, and early application is permitted. The Company does not anticipate that ASU 2016-15 will have a material effect on its consolidated and condensed financial statements and related disclosures.

In March 2016, the FASB issued ASU No. 2016-09 "Improvements to Employee Share-Based Payment Accounting," effective for annual and interim periods for public companies beginning after December 15, 2016, with a cumulative-effect and prospective approach to be used for implementation. ASU 2016-09 changes several aspects of the accounting for share-based payment award transactions including accounting for income taxes, classification of excess tax benefits on the statement of cash flows, forfeitures, minimum statutory tax withholding requirements and classification of employee taxes paid on the statement of cash flows when an employer withholds shares for tax-withholding purposes. The Company adopted ASU 2016-09 as of the quarter ended March 31, 2017 on a retrospective basis. Adoption of this guidance affected the statement of cash flows as of December 31, 2016 as follows (in thousands):

Increase in net cash provided by operating activities of approximately $1,906
Increase in net cash used in financing activities of approximately $1,906

Adoption of this guidance affected the statement of cash flows as of December 31, 2015 as follows (in thousands):

Increase in net cash provided by operating activities of approximately $533
Increase in net cash used in financing activities of approximately $533

In February 2016, the FASB issued ASU No. 2016-02 "Leases (Topic 842)," effective for annual and interim periods for public companies beginning after December 15, 2018, with a modified retrospective approach to be used for implementation. The standard updates the previous lease guidance by requiring the recognition of a right-to-use asset and lease liability on the statement of financial position for 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 15, "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 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 adoption of this standard will result in an increase in the assets and liabilities on the Company's consolidated balance sheets. The quantitative impacts of the new standard are dependent on the leases in force at the time of adoption. As a result, the evaluation of the effect of the new standards will extend over future periods.

May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)." In March, April, and May 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. The Company will apply the modified retrospective approach. As part of the assessment, the Company formed an implementation work team, completed trainings on the new revenue recognition model and gathered our material revenue contracts covering current revenue streams for which we evaluated the impacts to the consolidated financial statements under the revised standards. In addition, the Company is evaluating the impacts of significant historical transactions under the new standard. As of December 31, 2017, the Company determined that the deferred gains recorded under the Carnero Gathering Disposition and Carnero Processing Disposition (defined below in Note 10, "Related Party Transactions") will be de-recognized under the new standard and a derivative asset could be recorded for the value of the earnout provision owed to us by SNMP. Under the modified retrospective approach, the balance of accumulated deficit will be adjusted on January 1, 2018.

Change in Accounting Principle

During the fourth quarter of 2017, we changed our method of accounting for oil and gas exploration and development activities from full cost to the successful efforts method of accounting. Financial information for prior periods has been recast to reflect retrospective application of the successful efforts method, as prescribed by the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 932 "Extractive Activities – Oil and Gas." Although the full cost method of accounting for oil and gas exploration and development activities continues to be an acceptable alternative, the successful efforts method of accounting is the generally preferred method under U.S. GAAP and is more widely used in the industry such that the change improves the comparability of the Company's financial statements to its peers. Changing to the successful efforts method of accounting is expected to provide greater transparency in results of our assets, enhance operating decision making and capital allocation processes and eliminate proved property impairments based on historical prices, which are not indicative of fair value of our assets. 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. Successful efforts also provides for the assessment of potential property impairments under Accounting Standards Codification (ASC) 360 "Property, Plant, and Equipment" by comparing the net carrying value of oil and 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 gas properties exceeded 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 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.

Principles of Consolidation

The Company's 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 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, embedded derivatives and asset retirement obligations, accrued oil and natural gas revenues and expenses and the allocation of general and administrative expenses. Actual results could differ materially from those estimates.

Cash Equivalents

Cash and cash equivalents consist primarily of cash on deposit, money market accounts and investment grade commercial paper that are readily convertible into cash and purchased with original maturities of three months or less.

Oil and Natural Gas Receivables

The majority of the Company's receivables arise from sales of oil, natural gas liquids ("NGLs") or natural gas. The Company does not have any off-balance-sheet credit exposure related to its customers. Receivables from the sale of oil and natural gas are generally unsecured. Allowances for doubtful accounts are determined based on management's assessment of the creditworthiness of the customer. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are written off against the allowance for doubtful accounts only after all the collection attempts have been exhausted. At December 31, 2017 and 2016, management believed that all balances were fully collectible and no allowance for doubtful accounts was deemed necessary.

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. Proceeds from the sale or disposition of oil and natural gas properties are applied to reduce net capitalized costs unless the sale or disposition causes a significant change in the relationship between costs and the estimated quantities of proved reserves.

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 with production of the same converted to a common unit of measure based upon the relative energy content of the hydrocarbons. The Company groups its oil and 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 amortization are transferred to proved oil and natural gas properties amortization begins. All other properties 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 depreciation, depletion and amortization 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. Net capitalized costs of proved oil and natural gas properties are compared to estimated undiscounted future net cash flows using management's expectations of future oil and natural gas prices. 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. The estimated future cash flows used to determine whether an impairment is present and the related fair value calculations are typically based on judgmental assessments of future production, commodity prices, operating expenses, and capital expenditures, utilizing the available information. 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 are expected to impact the realizable price. We did not record a proved property impairment during the year ended December 31, 2017. During the year ended December 31, 2016, we recorded a proved property impairment of $3.7 million due to the decline of oil and natural gas prices during the first half of the year. We recorded impairment of $700.3 million to our proved oil and natural gas properties due to the significant decline in oil and natural gas prices during the year ended December 31, 2015.

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 a 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 impairment of $39.6 million to our unproved oil and natural gas properties for the year ended December 31, 2017 due to a write-down of our TMS acreage to fair value. We recorded impairments of $43.6 million and $23.7 million to our unproved oil and natural gas properties due to acreage abandonment from changes in development plan for the years ended December 31, 2016 and December 31, 2015, respectively. The costs of retaining unproved properties and the impairment of unsuccessful leases, are included in “Impairment expense” in the Company’s Consolidated Statements of Operations.

Based on management’s review and current operating plans, approximately 4%, 4% and 2% of the unproved property balance at December 31, 2017 is expected to be developed and added to the amortization base during the years 2018, 2019 and 2020, respectively. The remaining balances in unproved properties relate to project areas that will not be thoroughly evaluated until after 2020, and represent leasehold interests that have expiration dates beginning in 2020 or leasehold interests that are currently held by production and/or continuous operations.

Oil and Natural Gas Reserve Quantities

The Company’s most significant estimates relate to its proved oil and natural gas reserves. The estimates of oil and natural gas reserves as of December 31, 2017, 2016 and 2015 are based on reports prepared by a third-party engineering firm, Ryder Scott Company, L.P. (“Ryder Scott”).

Estimates of proved reserves are based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Ryder Scott has historically prepared a reserve and economic evaluation of the Company’s properties, utilizing information provided to it by management and other information available, including information from the operators of the property.

The standards of the FASB and rules of the SEC permit the use of new technologies to determine proved reserve estimates if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volume estimates. These rules allow, but do not require, companies to disclose their probable and possible reserves to investors in documents filed with the SEC.

In addition, the disclosure guidelines require companies to report oil and natural gas reserves using an average price based upon the prior 12-month first-day-of-the-month price rather than a period-end price.

Reserves and their relation to estimated future net cash flows impact the depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. The reserve estimates and the projected cash flows derived from these reserve estimates are prepared in accordance with SEC guidelines. The independent engineering firm noted above adheres to these guidelines when preparing their reserve reports. The accuracy of the reserve estimates is a function of many factors including the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered.

Debt Issuance Costs

Debt issuance costs relating to long-term debt have been deferred and are being amortized and recorded as interest expense over the term of the related debt instrument. During 2017, the Company capitalized approximately $18.7 million in costs associated with the incurrence of the SN UnSub Credit Agreement (as defined in "Note 6. Debt"). During 2016, the Company capitalized approximately $0.1 million in costs associated with the filing of a Form S-3 Registration Statement, and capitalized approximately $1.6 million associated with amending our Second Amended and Restated Agreement (as defined in "Note 6. Debt"). During 2015, the Company capitalized approximately $0.4 million in costs associated with amending our Second Amended and Restated Agreement. At December 31, 2017 and December 31, 2016, the Company had approximately $47.2 million and $35.0 million, respectively, of debt issuance costs (net of accumulated amortization of $34.5 million and $22.5. million, respectively) remaining that are being amortized over the terms of the respective debt. In accordance with ASU 2015-03, "Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs," the debt issuance costs related to the issuance of the 6.125% Notes and Second Amended and Restated Agreement are presented on the balance sheet as a direct deduction from the long-term debt.

Environmental Expenditures

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally not discounted unless the timing of cash payments for the liability is fixed or reliably determinable.

Liabilities for loss contingencies, including environmental remediation costs arising from claims, assessments, litigation, fines, and penalties and other sources, are recorded when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated. Recoveries of environmental remediation costs from third parties, which are probable of realization, are separately recorded and are not offset against the related environmental liability.

Management believes the Company is currently in compliance with all applicable federal, state and local regulations associated with its properties. Accordingly, no environmental remediation liability or loss associated with the Company's properties was recorded as of December 31, 2017 and 2016.

Asset Retirement Obligations

Asset retirement obligations represent the present value of the estimated cash flows expected to be incurred to plug, abandon and remediate producing properties, excluding salvage values, at the end of their productive lives in accordance with applicable laws. The significant unobservable inputs to this fair value measurement include estimates of plugging, abandonment and remediation costs, well life, inflation and credit-adjusted risk-free rate. The inputs are calculated based on historical data as well as current estimates. When the liability is initially recorded, the carrying amount of the related long-lived asset is increased. Over time, accretion of the liability is recognized each period, and the capitalized cost is amortized over the useful life of the related asset and is included in “Depreciation, depletion, amortization and accretion” in the Company’s Consolidated Statements of Operations.

To estimate the fair value of an asset retirement obligation, the Company employs a present value technique, which reflects certain assumptions, including its credit-adjusted risk-free interest rate, inflation rate, the estimated settlement date of the liability and the estimated current cost to settle the liability. Changes in timing or to the original estimate of cash flows will result in change to the carrying amount of the liability.

Stock-Based Compensation

The Company records stock-based compensation expense for awards granted to its directors (for their services as directors) in accordance with the provisions of Accounting Standards Codification (“ASC”) Topic 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.

Stock-based compensation awards and phantom stock awards, including those awards with market performance acceleration conditions, granted to employees of the Sanchez Group (as defined in Note 8, “Stock-Based Compensation”) (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. In accordance with the guidance, the inclusion of market performance acceleration conditions does not change the accounting classification as compared to those awards without market performance acceleration conditions. The phantom stock awards are required to be settled in cash by the Company and are 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.

Revenue Recognition

Sales of oil, natural gas and NGLs are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred, and collectability of the revenue is probable. Delivery occurs and title is transferred when production has been delivered to a pipeline, railcar or truck, or a tanker lifting has occurred. The entitlement method of accounting is used for the sale of oil, natural gas and NGLs. Oil and natural gas imbalances are generated on properties for which two or more owners have the right to take production “in-kind” and, in doing so, take more or less than their respective entitled percentage. As of December 31, 2017, 2016 and 2015 there were no material oil and natural gas imbalances.

Sales to Major Customers

The Company's oil, natural gas and NGLs were sold to certain customers representing 10% or more of its total revenues for the years ended December 31, 2017, 2016 and 2015 as listed below:

	2017	2016	2015
Customer A	19%	2%	1%
Customer B	9%	14%	14%
Customer C	14%	0%	0%
Customer D	26%	33%	38%
Customer E	23%	20%	0%

Production is normally sold to relatively few customers. Substantially all of the Company's customers are concentrated in the oil and natural gas industry and revenue can be materially affected by current economic conditions, the price of certain commodities such as crude oil and natural gas and the availability of alternate purchasers. Management believes the loss of any of the Company's major customers would not have a long-term material adverse effect on the Company's operations.

General and Administrative Expenses

On December 19, 2011, the Company entered into a services agreement and other related agreements with Sanchez Oil & Gas Corporation ("SOG"), pursuant to which SOG (directly or through its subsidiaries) agreed to provide the Company with the services and data that the Company believes are necessary to manage, operate and grow its business, and the Company agreed to reimburse SOG for all direct and indirect costs incurred on its behalf (the "Services Agreement"). See detailed discussion of the Company's relationship with SOG in Note 10, "Related Party Transactions."

Derivative Instruments

The Company utilizes derivative instruments in order to manage price risk associated with future crude oil and natural gas production. Management sets and implements all of the hedging policies, including volumes, types of instruments and counterparties, on a monthly basis. The Company recognizes all derivatives as either assets or liabilities, measured at fair value, and recognizes changes in the fair value of derivatives in current earnings because it does not designate its derivatives as cash flow hedges.

Income Taxes

The Company accounts for income taxes using the asset and liability method. Deferred tax assets and liabilities arise from the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary difference and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Valuation allowances are established when necessary to reduce the deferred tax asset to the amount more likely than not to be recovered.

Additionally, the Company is required to determine whether it is more likely than not (a likelihood of more than 50%) that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position in order to record any financial statement benefit. If that step is satisfied, then the Company must measure the tax position to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that has greater than a 50% likelihood of being realized upon ultimate settlement. Any interest or penalties would be recognized as a component of income tax expense.

The Company applies significant judgment in evaluating its tax positions and estimating its provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact the Company’s financial position, results of operations and cash flows. The Company does not have any material uncertain tax positions during the years ended December 31, 2017 or 2016.

Earnings per Share

Basic net income (loss) per common share are computed using the two-class method. The two-class method is required for those entities that have participating securities. The two-class method is an earnings allocation formula that determines net income (loss) per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. The Company’s restricted shares of common stock (see Note 8, “Stock-Based Compensation”) are participating securities under ASC 260, “Earnings per Share,” because they may participate in undistributed earnings with common stock. Participating securities do not have a contractual obligation to share in the Company’s losses. Therefore, in periods of net loss, no portion of the loss is allocated to participating securities.

Diluted net income (loss) per common share reflect the dilutive effects of the participating securities using the two-class method or the treasury stock method, whichever is more dilutive. They also reflect the effects of the potential conversion of the Company’s Series A and Series B Preferred Stock using the if-converted method, if the effect is dilutive. In addition, they also reflect the effects of the warrants issued in connection with the Comanche Acquisition using the treasury stock method, if the effect is dilutive.

Note 3. Change in Accounting Principle

During the fourth quarter of 2017, the Company voluntarily changed its method of accounting for oil and 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 360 “Property, Plant and Equipment” by comparing the net carrying value of oil and 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 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 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. Our consolidated financial statements have been recast to reflect these differences for all periods presented, including the Consolidated Balance Sheets, Consolidated Statements of Operations, Consolidated Statements of Stockholders’ Equity, Consolidated Statements of Cash Flows and related information in Notes 2, 3, 4, 7, 9, 10, 12, 14, and 19.

Sanchez Energy Corporation

Notes to the Consolidated Financial Statements (Continued)

The following tables present the effects of the change to the successful efforts method in the statement of consolidated operations:

For the Year Ended December 31, 2017	Changes to the Consolidated Statement of Operations		
	Under Full Cost	Changes	As Reported Under Successful Efforts
	(In thousands, except per share data)		
Oil and natural gas production expenses	$ 253,368	$ (8,907)	$ 244,461
Exploration expenses	—	5,755	5,755
Depreciation, depletion, amortization and accretion	199,087	(22,009)	177,078
Impairment of oil and natural gas properties	—	39,574	39,574
Other income (expense)	7,351	3,751	11,102
Gain on disposal of assets	10,202	71,753	81,955
Income tax benefit (expense)	2,336	—	2,336
Net loss	(17,899)	61,091	43,192
Net income allocable to participating securities	—	—	—
Net loss attributable to common stockholders	$ (96,145)	$ 61,091	$ (35,054)
			—
Net loss per common share - basic and diluted	$ (1.27)	$ 0.81	$ (0.46)

For the Year Ended December 31, 2016	Changes to the Consolidated Statement of Operations		
	Under Full Cost	Changes	As Reported Under Successful Efforts
	(In thousands, except per share data)		
Oil and natural gas production expenses	$ 164,567	$ (8,907)	$ 155,660
Exploration expenses	—	403	403
Depreciation, depletion, amortization and accretion	159,760	(12,275)	147,485
Impairment of oil and natural gas properties	169,046	(121,665)	47,381
Gain on disposal of assets	112,294	(26,972)	85,322
Income tax benefit (expense)	(1,825)	—	(1,825)
Net loss	(256,958)	115,472	(141,486)
Net income allocable to participating securities	—	—	—
Net loss attributable to common stockholders	$ (272,906)	$ 115,472	$ (157,434)
			—
Net loss per common share - basic and diluted	$ (4.63)	$ 1.96	$ (2.67)

For the Year Ended December 31, 2015	Changes to the Consolidated Statement of Operations Under Full Cost	Changes	As Reported Under Successful Efforts
	(In thousands, except per share data)		
Oil and natural gas production expenses	156,528	(1,856)	154,672
Exploration expenses	—	1,982	1,982
Depreciation, depletion, amortization and accretion	344,572	(80,193)	264,379
Impairment of oil and natural gas properties	1,365,000	(641,029)	723,971
Gain on disposal of assets	—	—	—
Income tax benefit (expense)	(7,600)	7,442	(158)
Net loss	(1,454,627)	728,538	(726,089)
Net income allocable to participating securities	—	—	—
Net loss attributable to common stockholders	$ (1,470,635)	$ 728,538	$ (742,097)
			—
Net loss per common share - basic and diluted	$ (25.70)	$ 12.73	$ (12.97)

The following tables present the effects of the change to the successful efforts method in the statement of consolidated cash flows:

For the Year Ended December 31, 2017	Changes to the Consolidated Statement of Cash Flows Under Full Cost	Change	As reported Under Successful Efforts
		(In thousands)	
Net loss	$ (17,899)	$ 61,091	$ 43,192
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	199,087	(22,009)	177,078
Impairment of oil and natural gas properties	—	39,574	39,574
Gain on sale of oil and natural gas properties	(10,202)	(71,753)	(81,955)
Amortization of deferred gain on Catarina Midstream Sale	(14,813)	(8,907)	(23,720)
Deferred taxes	(737)	—	(737)
Net cash provided by operating activities	294,093	(2,004)	292,089
Payments for oil and natural gas properties	(502,338)	2,004	(500,334)
Net cash used in investing activities	(1,384,804)	2,004	(1,382,800)
Net cash provided by (used in) financing activities	773,228	—	773,228
Increase (decrease) in cash and cash equivalents	(317,483)	—	(317,483)
Cash and cash equivalents, beginning of period	501,917	—	501,917
Cash and cash equivalents, end of period	$ 184,434	$ —	$ 184,434

For the Year Ended December 31, 2016	Changes to the Consolidated Statement of Cash Flows Under Full Cost	Change	As reported Under Successful Efforts
		(In thousands)	
Net loss	$ (256,958)	$ 115,472	$ (141,486)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	159,760	(12,275)	147,485
Impairment of oil and natural gas properties	169,046	(121,665)	47,381
Gain on sale of oil and natural gas properties	(112,294)	26,972	(85,322)
Amortization of deferred gain on Catarina Midstream Sale	(14,813)	(8,907)	(23,720)
Deferred taxes	—	—	—
Net cash provided by operating activities	183,157	(403)	182,754
Payments for oil and natural gas properties	(313,342)	403	(312,939)
Net cash used in investing activities	(108,637)	403	(108,234)
Net cash provided by (used in) financing activities	(7,651)	—	(7,651)
Increase (decrease) in cash and cash equivalents	66,869	—	66,869
Cash and cash equivalents, beginning of period	435,048	—	435,048
Cash and cash equivalents, end of period	$ 501,917	$ —	$ 501,917

For the Year Ended December 31, 2015	Changes to the Consolidated Statement of Cash Flows Under Full Cost	Change	As reported Under Successful Efforts
		(In thousands)	
Net income (loss)	$ (1,454,627)	$ 728,538	$ (726,089)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	344,572	(80,193)	264,379
Impairment of oil and natural gas properties	1,365,000	(641,029)	723,971
Amortization of deferred gain on Catarina Midstream Sale	(3,086)	(1,856)	(4,942)
Deferred Taxes	7,443	(7,442)	1
Net cash provided by operating activities	272,558	(1,982)	270,576
Payments for oil and natural gas properties	(656,136)	1,982	(654,154)
Net cash used in investing activities	(294,331)	1,982	(292,349)
Net cash provided by (used in) financing activities	(16,893)	—	(16,893)
Increase (decrease) in cash and cash equivalents	(38,666)	—	(38,666)
Cash and cash equivalents, beginning of period	473,714	—	473,714
Cash and cash equivalents, end of period	$ 435,048	$ —	$ 435,048

The following tables present the effects of the change to the successful efforts method in the consolidated balance sheet:

December 31, 2017	Changes to Consolidated Balance Sheet — Under Full Cost	Changes (In thousands)	As Reported Under Successful Efforts
Oil and natural gas properties:			
Unproved oil and natural gas properties	398,212	393	398,605
Proved oil and natural gas properties	4,462,171	(1,331,764)	3,130,407
Total oil and natural gas properties	4,860,383	(1,331,371)	3,529,012
Less: Accumulated depreciation, depletion, amortization and impairment	(2,931,039)	1,429,486	(1,501,553)
Total oil and natural gas properties, net	1,929,344	98,115	2,027,459
Total assets	$ 2,372,520	$ 98,115	$ 2,470,635
Current liabilities:			
Other	106,337	8,907	115,244
Total current liabilities	453,621	8,907	462,528
Other liabilities	49,520	15,960	65,480
Total liabilities	2,487,396	24,867	2,512,263
Accumulated deficit	(1,905,404)	73,248	(1,832,156)
Total stockholders' equity (deficit)	(542,388)	73,248	(469,140)
Total liabilities and stockholders' equity (deficit)	$ 2,372,520	$ 98,115	$ 2,470,635

December 31, 2016	Changes to Consolidated Balance Sheet — Under Full Cost	Changes (In thousands)	As Reported Under Successful Efforts
Oil and natural gas properties:			
Unproved oil and natural gas properties	231,424	(6,401)	225,023
Proved oil and natural gas properties	3,164,115	(1,314,383)	1,849,732
Total oil and natural gas properties	3,395,539	(1,320,784)	2,074,755
Less: Accumulated depreciation, depletion, amortization and impairment	(2,736,951)	1,366,715	(1,370,236)
Total oil and natural gas properties, net	658,588	45,931	704,519
Total assets	$ 1,286,280	$ 45,931	$ 1,332,211
Current liabilities:			
Other	22,201	8,907	31,108
Total current liabilities	176,997	8,907	185,904
Other liabilities	64,333	24,866	89,199
Total liabilities	1,982,420	33,773	2,016,193
Accumulated deficit	(1,809,260)	12,158	(1,797,102)
Total stockholders' equity (deficit)	(696,140)	12,158	(683,982)
Total liabilities and stockholders' equity (deficit)	$ 1,286,280	$ 45,931	$ 1,332,211

Note 4. Acquisitions and Divestitures

Our acquisitions are accounted for under the acquisition method of accounting in accordance with ASC Topic 805, "Business Combinations" ("ASC Topic 805"). 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 consolidated financial statements since the closing dates of the acquisitions.

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 and is subject to normal and customary post-closing adjustments. 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 approximately $44 million in cash, after preliminary closing adjustments, and Lonestar's Series B Convertible Preferred Stock which subsequently converted into 1.5 million shares of Lonestar's Class A Common Stock (the "Marquis Disposition"). Consideration received from the Marquis Disposition was based on a January 1, 2017 effective date and is subject to other normal and customary post-closing adjustments. Assets conveyed pursuant to the Marquis Disposition consist 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 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, after preliminary closing adjustments (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)). 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 "SN Comanche Assets"). The Comanche Assets are primarily located in the Western Eagle Ford and significantly expanded the Company's 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

In addition, as is common in our industry, we are party to certain gathering agreements that obligate us to deliver a specified volume of production over a defined time horizon. In particular, with respect to the Comanche Assets, we, as the operator, on behalf of ourselves and the other working interest partners, are party to two gathering agreements that require us to deliver variable monthly quantities through 2034. Gross volumes under these contracts peak at approximately 63,000 Bbl per day (approximately 14,800 Bbl per day net) of crude oil and condensate in 2020 and 430,000 Mcf per day (approximately 101,400 Mcf per day net) of natural gas in 2022, and then decrease annually thereafter through the end of the contracts. We are currently meeting our minimum volume commitments under these contracts and expect to continue to fulfill these obligations based on our anticipated development plan for the Comanche Assets.

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 gas interests and associated assets located in Dimmit County, Frio County, LaSalle County, Zavala County and McMullen County, 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 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 are 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.

Typically, proceeds from the sale or disposition of oil and natural gas properties are applied to reduce net capitalized costs with no gain or loss recognized, unless the sale or disposition causes a significant change in the relationship between costs and the estimated quantities of proved reserves. However, in circumstances where treating a sale like a normal retirement would result in a significant change in the relationship between costs and the estimated quantities of proved reserves, judgment should be applied. 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 has recorded additional gains totaling $10.4 million during the twelve months ended December 31, 2017.

Production Asset Transaction

On November 22, 2016, the Company completed the sale of certain non-core producing oil and gas assets, located in South Texas, to SNMP for an adjusted purchase price of approximately $24.2 million in cash (the "Production Asset Transaction"). The Production Asset Transaction includes working interests in 23 producing Eagle Ford wellbores located in Dimmit, LaSalle and Zavala counties in South Texas together with escalating working interests in an additional 11 producing wellbores located in the Palmetto Field in Gonzales County, Texas. The effective date of the Production Asset Transaction was July 1, 2016. For the escalating working interests conveyed in the 11 producing wellbores, the aggregate average working interest percentage initially conveyed was 17.92% per wellbore and, upon January 1 of each subsequent year after the closing, the purchaser's working interest has automatically increased in incremental amounts according to the purchase agreement through January 1, 2018, at which point the purchaser will own a 47.5% working interest and we will own a 2.5% working interest in each of the wellbores. The Company did not record any gains or losses related to the Production Asset Transaction.

Western Catarina Midstream Divestiture

On October 14, 2015, the Company and SN Catarina, LLC ("SN Catarina") completed the sale of SN Catarina's interests in Catarina Midstream, LLC, a wholly-owned subsidiary of SN Catarina ("Catarina Midstream"), which as of the closing included certain midstream gathering lines and associated assets and interests located in Dimmit County and Webb County, Texas and 105,263 SNMP common units to SNMP for an adjusted purchase price of $345.8 million in cash (the "Western Catarina Midstream Divestiture"). In connection with the closing of the Western Catarina Midstream Divestiture, SN Catarina and Catarina Midstream entered into a Firm Gathering and Processing Agreement (the "Gathering Agreement") on October 14, 2015 for an initial term of 15 years under which production from approximately 35,000 acres in Dimmit County and Webb County, Texas will be dedicated for gathering by Catarina Midstream. In addition, for the first five years of the Gathering Agreement, SN Catarina will be required to meet a minimum quarterly volume delivery commitment of 10,200 Bbl per day of crude oil and condensate and 142,000 Mcf per day of natural gas, subject to certain adjustments. SN Catarina will be required to pay gathering and processing fees of $0.96 per barrel for crude oil and condensate and $0.74 per Mcf for natural gas that are tendered through the gathering system, in each case, subject to an annual escalation for a positive increase in the consumer price index. In addition, SN Catarina has, under certain circumstances, a right of first refusal during the term of the agreement and afterwards with respect to dispositions by Catarina Midstream of its ownership interest in the gathering system. The Company recorded a deferred gain of approximately $116.8 million as a result of Gathering Agreement being accounted for as an operating lease. This deferred gain will be amortized straight-line over the firm commitment of five years as an offset to the transportation fees paid to SNMP under the Gathering Agreement.

Palmetto Disposition

On March 31, 2015, we completed our disposition to a subsidiary of SNMP of escalating amounts of partial working interests in 59 wellbores located in Gonzales County, Texas (the "Palmetto Disposition") for an adjusted purchase price of approximately $83.4 million. The effective date of the transaction was January 1, 2015. The aggregate average working interest percentage initially conveyed was 18.25% per wellbore and, upon January 1 of each subsequent year after the closing, the purchaser's working interest will automatically increase in incremental amounts according to the purchase agreement until January 1, 2019, at which point the purchaser will own a 47.5% working interest and we will own a 2.5% working interest in each of the wellbores. We received consideration consisting of approximately $81.4 million in cash, after purchase price adjustments, and 1,052,632 common units of SNMP (the "SNMP Common Units") valued at approximately $2.0 million as of the date of the closing. The SNMP Common Units were later sold back to SNMP in October 2015 as part of the Western Catarina Midstream Divestiture described above. The Company did not record any gains or losses related to the Palmetto Disposition.

Results of Operations and Pro Forma Operating Results

The following unaudited pro forma combined financial information for the years ended December 31, 2017 and 2016 is based on the historical consolidated financial statements of the Company adjusted to reflect as if the Comanche Acquisition and related financing had occurred on January 1, 2016. The unaudited pro forma combined financial information includes adjustments primarily for revenues and expenses for the acquired properties, depreciation, depletion, amortization and accretion, interest expense and debt issuance cost amortization for acquisition debt, and issuance cost amortization of the acquisition preferred financing. The unaudited pro forma combined financial statements give effect to the events set forth below:

- The Comanche Acquisition completed March 1, 2017.
- The issuance of 500,000 SN UnSub Preferred Units for $500 million to finance a portion of the Comanche Acquisition.
- The borrowing of $173.5 million on a $330 million senior secured reserve based revolving credit facility of SN UnSub to finance a portion of the Comanche Acquisition.
- Issuance of 1,455,000 shares of the Company's common stock to certain funds managed or advised by GSO Capital Partners LP ("GSO"), which is an investor in SN UnSub.
- Issuance of 45,000 shares of the Company's common stock to Intrepid Private Equity V-A, LLC ("Intrepid"), which is an investor in SN UnSub.
- Issuance of warrants to certain funds managed or advised by GSO (the "GSO Funds") to purchase 1,940,000 shares of the Company's common stock at an exercise price of $10 per share.
- Issuance of warrants to Intrepid to purchase 60,000 shares of the Company's common stock at an exercise price of $10 per share.
- Issuance of warrants to the Blackstone Warrantholders (as defined below) to purchase 6,500,000 shares of the Company's common stock at an exercise price of $10 per share.
- Issuance of 100 Class A Units in Gavilan Holdco (as defined below) to SN Comanche Manager, LLC ("SN Comanche Manager" or the "Manager").

	Year Ended December 31,	
	2017	**2016**
Revenues	$ 784,360	$ 693,843
Net income (loss) attributable to common stockholders	$ (6,458)	$ (242,847)
Net income (loss) per common share, basic and diluted	$ (0.09)	$ (3.38)

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

Post-Acquisition Operating Results

The amounts of revenue and excess of revenues over direct operating expenses included in the Company's condensed consolidated statements of operations for the year ended December 31, 2017 for the Comanche Acquisition are shown in the table that follows. Direct operating expenses include lease operating expenses and production and ad valorem taxes (in thousands):

	Year Ended December 31, 2017
Revenues	$ 255,282
Excess of revenues over direct operating expenses	$ 138,046

Note 5. Cash and Cash Equivalents

As of December 31, 2017 and 2016, cash and cash equivalents consisted of the following (in thousands):

	As of December 31,	
	2017	2016
Cash at banks	$ 135,363	$ 58,269
Money market funds	49,071	443,648
Total cash and cash equivalents	$ 184,434	$ 501,917

Note 6. Debt

Debt as of December 31, 2017 consisted of $1.15 billion face value of 6.125% Notes (defined below) maturing on January 15, 2023, $600 million principal amount of 7.75% Notes (defined below) maturing on June 15, 2021, $50.0 million related to the Second Amended and Restated Credit Agreement, $175.5 million related to the SN UnSub Credit Agreement, which is non-recourse to Sanchez Energy Corporation ("SN") and the other obligors on the 6.125% Notes, 7.75% Notes and the Second Amended and Restated Credit Agreement ("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), approximately $24.0 million related to the SR Credit Agreement (defined below), which is Non-Recourse to the Company and to the obligors under the SN UnSub Credit Agreement and the Non-Recourse Subsidiary Term Loan, and approximately $4.2 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.

As of December 31, 2017 and 2016 the Company's debt consisted of the following:

	Interest Rate	Original Maturity Date	Amount Outstanding (in thousands) as of December 31, 2017	December 31, 2016
Short-Term Debt				
SR Credit Agreement[1][2]	Variable	August 8, 2018	$ 23,996	$ —
Total short-term debt			$ 23,996	$ —
Long-Term Debt				
Second Amended and Restated Credit Agreement	Variable	June 30, 2019	$ 50,000	$ —
SN UnSub Credit Agreement[1]	Variable	March 1, 2022	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	4,164	—
6.125% Notes	6.125%	January 15, 2023	1,150,000	1,150,000
			1,979,664	1,750,000
Unamortized discount on Additional 7.75% Notes			(3,126)	(4,030)
Unamortized premium on Additional 6.125% Notes			1,360	1,629
Unamortized debt issuance costs			(47,215)	(34,832)
Total long-term debt			$ 1,930,683	$ 1,712,767

(1) These debt instruments are Non-Recourse to the Company.

(2) Bears a weighted-average interest rate of 5.122%.

The components of interest expense are (in thousands):

	Year Ended December 31, 2017	2016	2015
Interest on Senior Notes	$ (116,938)	$ (116,938)	$ (116,938)
Interest on SN UnSub Credit Agreement	(7,639)	—	—
Interest on SR Credit Agreement	(105)	—	—
Interest on Non-Recourse Subsidiary Term Loan	(65)	—	—
Interest expense and commitment fees on Second Amended and Restated Credit Agreement	(2,135)	(1,561)	(1,229)
Amortization of debt issuance costs	(12,647)	(7,840)	(7,529)
Amortization of discount on Additional 7.75% Notes	(904)	(904)	(904)
Amortization of premium on Additional 6.125% Notes	270	270	201
Total interest expense	$ (140,163)	$ (126,973)	$ (126,399)

Credit Facilities

Second Amended and Restated Credit Agreement

On June 30, 2014, the Company, as borrower, and certain of its operating subsidiaries, as loan parties, entered into a revolving credit facility represented by a $1.5 billion Second Amended and Restated Credit Agreement with Royal Bank of Canada, as the administrative agent, and the lenders party thereto (together with all subsequent amendments prior to January 1, 2018, the ''Second Amended and Restated Credit Agreement''). The Second Amended and Restated Credit Agreement provided for the issuance of letters of credit, limited in the aggregate to the lesser of $80 million and the total availability thereunder. As of December 31, 2017, there were $50 million in borrowings and no letters of credit outstanding under the Second Amended and Restated Credit Agreement, which had a borrowing base of $350 million and aggregate elected commitments of $300 million. Availability under the Second Amended and Restated Credit Agreement was at all times subject to customary conditions and the then-applicable borrowing base and aggregate elected commitment amount. As of December 31, 2017, $250 million of the $300 million aggregate elected commitment amount was available for future revolver borrowings.

The Second Amended and Restated Credit Agreement was scheduled to mature on June 30, 2019. The borrowing base under the Second Amended and Restated Credit Agreement was redetermined semi-annually by the lenders based on, among other things, an evaluation of the Company's and its restricted subsidiaries' oil and natural gas reserves. Semi-annual redeterminations of the borrowing base generally occurred on or before April 1 and October 1 of each year. The borrowing base was also subject to, among other things, (i) automatic reduction by 25% of the amount of certain issuances of high yield debt and second lien debt, (ii) interim redetermination at the election of the Company once between each scheduled redetermination, (iii) interim redetermination at the election of a majority of the lenders once between each scheduled redetermination, and (iv) if the required lenders so directed, in connection with asset sales and swap terminations during the period since the most recent borrowing base determination with a combined borrowing base value of more than 10% of the value of the proved developed oil and gas properties included in the most recent reserve report, a reduction in an amount equal to the borrowing base value, as determined by the administrative agent in its reasonable judgment, of such sold assets and liquidated swaps.

The Company's obligations under the Second Amended and Restated Credit Agreement were guaranteed by certain of the Company's existing and future subsidiaries and were secured by a first priority lien on substantially all of the Company's assets and the assets of its existing and future subsidiaries, including a first priority lien on all ownership interests in existing and future subsidiaries, in each case, subject to customary exceptions; provided, however, that the guarantee and first priority lien requirements did not extend to existing and future subsidiaries designated as "unrestricted subsidiaries," including SN UnSub.

At the Company's election, interest on borrowings under the Second Amended and Restated Credit Agreement was calculated based on an alternate base rate ("ABR") or an adjusted Eurodollar (LIBOR) rate, in each case, plus an applicable margin. The applicable margin varied from 1.00% to 2.00% for ABR borrowings and from 2.00% to 3.00% for Eurodollar (LIBOR) borrowings and letters of credit, if any, depending on the Company's utilization of the borrowing base. The Company was also required to pay a commitment fee of 0.50% per annum on any unused aggregate elected commitment amount. Interest on ABR borrowings and the commitment fee were generally payable quarterly. Interest on Eurodollar (LIBOR) borrowings were generally payable at the applicable maturity date, or at three-month intervals for Eurodollar (LIBOR) borrowings with an interest period of more than three months' duration.

The Second Amended and Restated Credit Agreement contained various affirmative and negative covenants and events of default that limited the Company's ability to, among other things, incur indebtedness, make restricted payments, grant liens, consolidate or merge, dispose of certain assets, make investments, engage in transactions with affiliates, enter into hedge transactions, and make acquisitions. The Second Amended and Restated Credit Agreement also provided for cross default between the Second Amended and Restated Credit Agreement and the other debt (including debt under the 6.125% Notes and the 7.75% Notes) and obligations in respect of hedging agreements (on a mark-to-market basis), of the Company and its restricted subsidiaries, in an aggregate principal amount in excess of $10 million. Furthermore, the Second Amended and Restated Credit Agreement contained financial covenants that required the Company to satisfy the following tests: (i) current assets plus undrawn borrowing capacity on the Second Amended and Restated Credit Agreement to current liabilities of at least 1.0 to 1.0 as of the last day of each fiscal quarter, and (ii) net first lien debt (defined as the excess of first lien debt over cash) to consolidated last twelve months EBITDA of not greater than 2.0 to 1.0 as of the last day of any fiscal quarter. As of December 31, 2017, the Company was in compliance with the covenants of the Second Amended and Restated Credit Agreement.

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

On February 14, 2018, we refinanced the outstanding loans under the Second Amended and Restated Credit Agreement through the issuance of $500 million in aggregate principal amount of the 7.25% Senior Secured Notes and we concurrently amended and restated the Second Amended and Restated Credit Agreement into the $25 million Third Amended and Restated Credit Agreement. See " – Note 20, Subsequent Events."

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 December 31, 2017, there were approximately $175.5 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 November 6, 2017, the borrowing base of the SN UnSub Credit Agreement was reaffirmed at $330 million in conjunction with the fall redetermination. The next regularly scheduled borrowing base redetermination is expected in the second quarter 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.

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 December 31, 2017, 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 1.75% to 2.75% for ABR borrowings and from 2.75% to 3.75% 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 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 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 arm's length basis. Furthermore, the SN UnSub Credit Agreement contains financial covenants that require SN UnSub to satisfy certain specified financial ratios, including the following tests: (i) a current assets plus undrawn borrowing capacity on the SN UnSub Credit Agreement 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 EBITDA 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 December 31, 2017, 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 December 31, 2017, we had approximately $24 million in additional past due borrowings under an existing credit facility of an unrestricted subsidiary acquired as part of the SR legal settlement (the "SR Credit Agreement"), which debt is Non-Recourse to the Company and to the obligors on 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, the administrative agent and the lenders 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 million in borrowings due under the SR Credit Agreement or successfully renegotiate the terms of such facility, then the administrative agent or the lenders under that facility could proceed against the collateral securing that debt, consisting of substantially all of Sanchez Resources' TMS assets (approximately 12,500 net acres). See "Item 8. Financial Statements and Supplementary Data – Note 10. Related Party Transactions".

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 our Second Amended and Restated Credit Agreement) to the extent of the value of the assets securing such debt. The 7.75% Notes are fully and unconditionally guaranteed (except for customary release provisions) on a joint and several senior unsecured basis by the subsidiary guarantors party to the indenture governing the 7.75% Notes. To the extent set forth in the indenture governing the 7.75% Notes, certain of our subsidiaries will be required to fully and unconditionally guarantee the 7.75% Notes on a joint and several senior unsecured basis in the future.

The indenture governing the 7.75% Notes, among other things, restricts our ability and our restricted subsidiaries' ability to: (i) incur, assume, or guarantee additional indebtedness or issue certain types of equity securities; (ii) pay distributions on, purchase or redeem shares or purchase or redeem subordinated debt; (iii) make certain investments; (iv) enter into certain transactions with affiliates; (v) create or incur liens on their assets; (vi) sell assets; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) restrict distributions or other payments from the Company's restricted subsidiaries; and (ix) designate subsidiaries as unrestricted subsidiaries.

We have the option to redeem all or a portion of the 7.75% Notes, at any time on or after June 15, 2017 at the applicable redemption prices specified in the indenture governing such notes plus accrued and unpaid interest. In addition, we may be required to make an offer to repurchase the 7.75% Notes upon a change of control or if we sell certain of our assets.

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

6.125% Senior Notes Due 2023

On June 27, 2014, the Company completed a private offering of $850 million in aggregate principal amount senior unsecured 6.125% notes due 2023 (the "Original 6.125% Notes"). Interest on the notes is payable on each July 15 and January 15. The Company received net proceeds from this offering of approximately $829 million, after deducting initial purchasers' discounts and estimated offering expenses, which the Company used to repay all of the $100 million in borrowings outstanding under its previous credit facility and to finance a portion of the purchase price of the Catarina Acquisition. We used the remaining proceeds from the offering to fund a portion of the remaining 2014 capital budget and for general corporate purposes. The Original 6.125% Notes are the senior unsecured obligations of the Company and are guaranteed on a joint and several senior unsecured basis by, with certain exceptions, substantially all of the Company's existing and future subsidiaries.

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

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

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

The Company has the option to redeem all or a portion of the 6.125% Notes, at any time on or after July 15, 2018 at the applicable redemption prices specified in the indenture governing such notes 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 make an offer 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 Senior Notes and Delaware Trust was appointed as successor Trustee. No other changes to the indentures for the 6.125% Notes or the 7.75% Notes were made at the time of the change in Trustee.

Note 7. 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 December 31, 2017, 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 from this offering of $135.9 million (after deducting underwriters' discounts fees of approximately $7.8 million) from the sale of the shares of common stock. The Company used the net proceeds of the offering for general corporate purposes, including working capital.

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 December 31, 2017, 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 Company's Board of Directors (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 December 31, 2017, all dividends accumulated through that date had been paid. The dividends accrued for the period from October 1 to December 31, 2017, were declared by the Board and paid with the Company's common stock on January 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 after October 5, 2017, the Company may at its option cause all outstanding shares of the Series A Preferred Stock to be automatically converted into common stock at the conversion price, if, among other conditions, the closing sale price (as defined) of the Company's common stock equals or exceeds 130% of the conversion price for a specified period prior to the conversion.

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

Series B Preferred Stock Offering—On March 26, 2013, the Company completed a private placement of 4,500,000 shares of Series B Preferred Stock. The issue price of each share of the Series B Preferred Stock was $50.00. The Company received net proceeds from the private placement of $216.6 million, after deducting placement agent's fees and offering costs of $8.4 million. The Company used the net proceeds from this offering to fund a portion of the purchase price for the acquisition of certain assets in Dimmit, Frio, LaSalle, and Zavala Counties, Texas in the Eagle Ford Shale.

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 December 31, 2017, 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 December 31, 2017, all dividends accumulated through that date had been paid. The dividends accrued for the period from October 1 to December 31, 2017, were declared by the Board and paid with the Company's common stock on January 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, our 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 (as defined below) and the issuance of warrants to the Blackstone Warrantholders (as defined below) 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 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 March 1, 2017 (the "Effective Date"), pursuant to the Amended and Restated LLC Agreement (the "LLC Agreement") of Gavilan Resources Holdco, LLC ("GRHL" or "Gavilan Holdco"), GRHL authorized and issued a total of 100 Class A Units ("Class A Units") to SN Comanche Manager, a wholly owned unrestricted subsidiary of the Company. 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.

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 ("SN UnSub Preferred Units") for $485,000,000 and Intrepid purchased 15,000 SN UnSub Preferred Units for

$15,000,000. 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 debt 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 consolidated balance sheet consisting of the following as of December 31, 2017 (in thousands):

	December 31, 2017
Mezzanine equity beginning balance	$ —
Private placement of SN UnSub Preferred Units	500,000
Discount	(90,527)
Accretion of discount	18,039
Dividends accrued [(1)]	41,667
Dividends paid [(2)]	(41,667)
Total mezzanine equity	$ 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 are prohibited through February 28, 2018, and thus, the dividends for the periods presented are deemed to have been paid in kind and accrued.

(2) Dividends 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 any amounts holders of the

SN UnSub Preferred Units are entitled to receive, and shall be offset against any amounts holders of SN UnSub Preferred Units are entitled to receive.

Earnings (Loss) Per Share—The following table shows the computation of basic and diluted net earnings (loss) per share for the years ended December 31, 2017, 2016 and 2015 (in thousands, except per share amounts):

	Year Ended December 31,		
	2017	2016	2015
Net income (loss)	$ 43,192	$ (141,486)	$ (726,089)
Less:			
Preferred stock dividends	(15,948)	(15,948)	(16,008)
Preferred unit dividends and distributions	(44,259)	—	—
Preferred unit amortization	(18,039)	—	—
Net loss allocable to participating securities(1)(2)	—	—	—
Net loss attributable to common stockholders	$ (35,054)	$ (157,434)	$ (742,097)
Weighted average number of unrestricted outstanding common shares used to calculate basic net loss per share	75,608	58,900	57,229
Dilutive shares(3)(4)(5)	—	—	—
Denominator for diluted loss per common share	75,608	58,900	57,229
Net loss per common share - basic and diluted	$ (0.46)	$ (2.67)	$ (12.97)

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

(2) For the years ended December 31, 2017, 2016 and 2015, no losses were allocated to participating restricted stock because such securities do not have a contractual obligation to share in the Company's losses.

(3) The year ended December 31, 2017 excludes 2,755,893 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 and 100,000 contingently issuable shares from the calculation of the denominator for diluted loss per common share as these shares were anti-dilutive.

(4) The year ended December 31, 2016 excludes 2,113,462 shares of weighted average restricted stock and 12,554,481 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 earnings (loss) per common share as these shares were anti-dilutive.

(5) The year ended December 31, 2015 excludes 2,663,010 shares of weighted average restricted stock and 12,529,314 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 earnings (loss) per common share as these shares were anti-dilutive.

Note 8. 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 May 21, 2015, subject to stockholder approval.

The Company’s directors and consultants as well as employees of SOG and its affiliates (excluding the Company) (collectively, 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 our 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 our Board or Compensation Committee in its discretion.

The LTIP is administered by the Compensation Committee of the Board as appointed by our Board. Our Board may terminate or amend the LTIP at any time with respect to any shares for which a grant has not yet been made. Our 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 shares of the 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 our 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 year ended December 31, 2017, the Company issued 200,334 shares of restricted common stock pursuant to the LTIP to six directors of the Company that vest within one year from the date of grant. Pursuant to ASC 718, stock-based compensation expense for these awards was based on their grant date fair value of $6.32 per share (the closing sales price of the Company’s common stock on the grant date) and is being amortized over the vesting period. The Company also issued approximately 2.1 million shares of restricted common stock pursuant to the LTIP to certain employees and consultants of SOG (including the Company’s officers), with whom the Company has a Services Agreement. The majority of these shares of restricted common stock vest in equal annual amounts over a three-year period.

During the year ended December 31, 2016, the Company issued 156,126 shares of restricted common stock pursuant to the LTIP to five directors of the Company that vest within one year from the date of grant. Pursuant to ASC 718, stock-based compensation expense for these awards was based on their grant date fair values of $8.00 and $5.81 per share (the closing sales price of the Company's common stock on the grant date) and is being amortized over the vesting period. The Company also issued approximately 4.4 million shares of restricted common stock pursuant to the LTIP to certain employees and consultants of SOG (including the Company's officers), with whom the Company has a Services Agreement. Approximately 3.3 million shares of restricted common stock vest in equal annual amounts over a three-year period and the remaining 1.1 million shares of restricted common stock (referred to below as PARS) cliff vest at the end of a five-year period or earlier if the common stock closing price equals or exceeds certain benchmarks as set forth in the forms of agreement.

During the year ended December 31, 2015, the Company issued 95,237 shares of restricted common stock pursuant to the LTIP to five directors of the Company that vest within one year from the date of grant. Pursuant to ASC 718, stock-based compensation expense for these awards was based on their grant date fair values of $12.65 and $9.80 per share (the closing sales price of the Company's common stock on the grant date) and is being amortized over the vesting period. The Company also issued approximately 3.4 million shares of restricted common stock pursuant to the LTIP to certain employees and consultants of SOG (including the Company's officers), with whom the Company has a Services Agreement. Approximately 3.3 million shares of restricted common stock vest in equal annual amounts over a three-year period and approximately 0.1 million shares of restricted common stock vest in equal annual amounts over a five-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").

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 year ended December 31, 2017, no shares of PARS were issued by the Company. During the year ended December 31, 2016, the Company issued approximately 1.1 million shares of PARS pursuant to the LTIP to certain employees of SOG (including the Company's officers), with whom the Company has a Services Agreement. These PARS cliff vest at the end of a five-year period or earlier if the common stock closing price equals or exceeds certain benchmarks as set forth in the forms of agreement.

During the year ended December 31, 2017, the Company issued approximately 2.2 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. The majority of these shares of Phantom Stock vest in equal annual amounts over a three-year period. No PAPS were issued during the year ended December 31, 2017.

During the year ended December 31, 2016, the Company issued approximately 4.0 million shares of Phantom Stock and PAPS pursuant to the LTIP to certain employees of SOG (including the Company's officers), with whom the Company has a Services Agreement. Approximately 2.8 million shares of Phantom Stock vest in equal annual amounts over a three-year period and the remaining 1.2 million shares of PAPS have cliff vesting at the end of a five-year period or earlier if the common stock closing price equals or exceeds certain benchmarks as set forth in the forms of agreement.

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 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 will be 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.

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.

	Year Ended December 31,		
	2017	2016	2015
Restricted stock awards, directors	$ 6,726	$ 1,000	$ 917
Restricted stock awards, non-employees	15,455	23,961	13,914
Performance awards	728	—	—
Phantom Stock awards	17,389	12,129	—
Total stock-based compensation expense	$ 40,298	$ 37,090	$ 14,831

Based on the $5.31 per share closing price of the Company's common stock on December 29, 2017, there was approximately $17.5 million of unrecognized compensation cost related to the non-vested restricted shares outstanding. The cost is expected to be recognized over a weighted average period of approximately 2.13 years.

Based on the $5.31 per share closing price of the Company's common stock on December 31, 2017, there was approximately $0.6 million of unrecognized compensation cost related to these non-vested PARS restricted shares outstanding. The cost is expected to be recognized over a weighted average period of approximately 3.29 years.

Based on the $5.31 per share closing price of the Company's common stock on December 31, 2017, there was approximately $11.8 million of unrecognized compensation cost related to the non-vested PAPS and Phantom Stock award shares outstanding. The cost is expected to be recognized over an average period of approximately 2.54 years.

Based on the estimated per share price of the Performance Awards on December 31, 2017, there was approximately $2.2 million of unrecognized compensation cost related to the Performance Awards. The cost is estimated to be recognized over a weighted average period of approximately 3.01 years.

A summary of the status of the non-vested restricted common shares and PARS as of December 31, 2017 is presented below (in thousands, except per share amounts):

	Number of Shares	Weighted Average Fair Value	Aggregate Intrinsic Value (in thousands)
Non-vested common stock at December 31, 2016	6,891,261	$ 9.18	$ 63,262
Granted	2,138,674	11.08	23,697
Vested	(4,022,495)	8.71	(35,036)
Forfeited	(110,712)	8.15	(902)
Non-vested common stock at December 31, 2017	4,896,728	$ 10.42	$ 51,021

As of December 31, 2017, approximately 8.3 million shares remain available for future issuance to participants under the LTIP.

A summary of the status of the non-vested Phantom Stock shares and PAPS for the year ended December 31, 2017 is presented below (in thousands, except per share amounts):

	Number of Shares	Weighted Average Fair Value	Aggregate Intrinsic Value (in thousands)
Non-vested common stock at December 31, 2016	4,012,413	$ 4.87	$ 19,540
Granted	2,163,240	11.07	23,947
Vested	(2,533,534)	8.81	(22,320)
Forfeited	(53,475)	10.49	(561)
Non-vested common stock at December 31, 2017	3,588,644	$ 5.74	$ 20,606

Note 9. Income Taxes

The components of the federal income tax provision for the years ended December 31, 2017, 2016 and 2015 are (in thousands):

	Year Ended December 31, 2017	2016	2015
Current expense (benefit) as a result of current operations	$ (1,599)	$ 1,825	$ 158
Deferred expense (benefit) as a result of current operations	257,358	(46,191)	(254,560)
Increase (Decrease) in valuation allowance	(258,095)	46,191	254,560
Net income tax expense (benefit)	$ (2,336)	$ 1,825	$ 158

Sanchez Energy Corporation

Notes to the Consolidated Financial Statements (Continued)

The difference between the statutory federal income taxes calculated using a U.S. federal statutory corporate income tax rate of 35% and the Company's effective tax rate of (5.7)% is summarized as follows (in thousands):

	Year Ended December 31,		
	2017	2016	2015
Income tax expense (benefit) at the federal statutory rate	$ 14,300	$ (48,882)	$ (254,077)
Officers' compensation limitation	9,570	3,115	1,328
State taxes (net of federal benefit)	2,607	(232)	(5,463)
Non-deductible general and administrative expenses	841	743	309
Percentage depletion carryforward	(86)	(144)	—
Other	(52)	39	—
Minimum Tax Credit Recoverability	(1,599)		
US Tax Reform - Impact to Deferreds	227,392	—	—
Differences between actual income taxes and amounts estimated in prior years	2,786	995	3,501
Income tax expense (benefit)	255,759	(44,366)	(254,402)
US Tax Reform - One-Time Valuation Allowance Change	(227,392)	—	—
Other Valuation Allowance Change	(30,703)	46,191	254,560
Net income tax expense (benefit)	$ (2,336)	$ 1,825	$ 158

The Company's deferred tax position reflects the net tax effects of the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax reporting. Significant components of the deferred tax assets and liabilities are as follows (in thousands):

	As of December 31,	
	2017	2016
Deferred tax assets (liabilities):		
Derivative assets (obligations)	$ 9,536	$ 12,516
Depreciable, depletable property, plant and equipment	(22,351)	138,120
Share-based compensation	936	12,408
Revenue recognition	3,593	7,077
Investments in joint ventures	(22,561)	5,064
Other	321	(2,007)
Federal net operating loss carryforward	364,922	420,302
State net operating loss carryforward	4,246	3,256
Deferred tax assets:	338,642	596,736
Valuation allowance	(338,642)	(596,736)
Total Deferred tax assets	$ —	$ —

As of December 31, 2017, the Company had NOLs of approximately $1,737.7 million which begin to expire in 2031. Additionally, the Company had net operating losses in the states of Montana, Mississippi, and Louisiana which will begin to expire in 2018, 2033 and 2026, respectively.

Management assesses the available positive and negative evidence to estimate if sufficient future taxable income will be generated to use the existing deferred tax assets. A significant piece of objective negative evidence evaluated was the cumulative loss incurred over the three-year period ended December 31, 2017.

On the basis of this evaluation, as of December 31, 2017, a valuation allowance of approximately $338.6 million has been recorded to record only the portion of the deferred tax asset that is more likely than not to be realized.

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

The Company files income tax returns in the U.S. and various state jurisdictions. Sanchez is no longer subject to examination by federal income tax authorities prior to 2014. State statutes vary by jurisdiction.

As of December 31, 2017, 2016 and 2015, 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 Topic 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 2017 financial results reflect the provisional income tax effects of the Tax Act for which the accounting under ASC Topic 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 December 31, 2017.

As of December 31, 2017, we had deferred tax assets primarily related to our net operating loss carryforwards. Prior to the Tax Act, the value of these deferred tax assets was recorded at the previous income tax rate of 35%, which represented their expected future benefit to us. As a result of the Tax Act, the future benefit of these deferred tax assets was re-measured at the new income tax rate of 21% and we recorded an approximate $227.4 million provisional non-cash adjustment (exclusive of a valuation allowance) for the year ended December 31, 2017. We determined the effects of the rate change using our best estimate of temporary book-to-tax differences. Upon final analysis and remeasurement of our deferred tax balances, the adjustment we recorded during the fourth quarter of 2017 to reflect the change in corporate income tax rates may need to be adjusted in subsequent periods.

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 10. Related Party Transactions

SOG, headquartered in Houston, Texas, is a privately owned full service oil and natural gas company engaged in the exploration and development of oil and natural gas primarily in the South Texas, Louisiana and onshore Gulf Coast areas on behalf of certain 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 Ms. 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% 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 a Services Agreement with SOG pursuant to which specified employees of SOG provide certain services with respect to the Company's business under the direction, supervision and control of SOG. Pursuant to this arrangement, SOG performs centralized corporate functions for the Company, such as general and administrative services, geological, geophysical and reserve engineering, lease and land administration, marketing, accounting, operational services, information technology services, compliance, insurance maintenance and management of outside professionals. The Company compensates SOG for the services at a price equal to SOG's cost of providing such services, including all direct costs and indirect administrative and overhead costs (including the allocable portion of salary, bonus, incentive compensation and other amounts paid to persons that provide the services on SOG's behalf) allocated in accordance with SOG's regular and consistent accounting practices, including for any such costs arising from amounts paid directly by other members of the Sanchez Group on SOG's behalf or borrowed by SOG from other members of the Sanchez Group, in each case, in connection with the performance by SOG of services on the Company's behalf. The Company also reimburses SOG for sales, use or other taxes, or other fees or assessments imposed by law in connection with the provision of services to the Company (other than income, franchise or margin taxes measured by SOG's net income or margin and other than any gross receipts or other privilege taxes imposed on SOG) and for any costs and expenses arising from or related to the engagement or retention of third party service providers.

Salaries and associated benefits of SOG employees are allocated to the Company at a fixed rate that is reviewed at least annually and adjusted, if needed, based on a detailed analysis of actual time spent by the professional staff on Company projects and activities. General and administrative expenses such as office rent, utilities, supplies and other overhead costs, are allocated on the same fixed rate as the SOG employee salaries. Expenses allocated to the Company for general and administrative expenses and oil and natural gas production expenses for the years ended December 31, 2017, 2016 and 2015 are as follows (in thousands):

	Year Ended December 31,		
	2017	2016	2015
Administrative fees	$ 67,381	$ 40,901	$ 30,430
Third-party expenses	5,881	5,001	5,427
Total included in general and administrative expenses and oil and natural gas production expenses	$ 73,262	$ 45,902	$ 35,857

As of December 31, 2017 and 2016, the Company had a net receivable from SOG and other members of the Sanchez Group of $4.5 million and a net receivable of $6.4 million, respectively, which is reflected as "Accounts receivable—related entities" in the consolidated balance sheets. The net receivable as of December 31, 2017 and 2016 consists primarily of advances paid related to leasehold and other costs paid to SOG.

As of December 31, 2017 and 2016, the Company had a net payable to SNMP of approximately $9.8 million and $9.0 million, respectively, that consists primarily of the accrual for fees associated with the Gathering Agreement related to the Western Catarina Midstream Divestiture, which is reflected in the "Accrued Liabilities – Other" account on the consolidated balance sheets. On June 30, 2017, the Gathering Agreement was amended to, among other things, provide for an additional, 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, with no such fee being payable thereafter, and to eliminate certain late payment fees from SN Catarina to SNMP. 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 continues month-to-month thereafter unless terminated by either party.

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 0.67%, 2.06%, 2.04% and 2.42%, respectively, of the SNMP common units outstanding as of December 31, 2017.

Production Asset Transaction

On November 22, 2016, we completed the Production Asset Transaction previously discussed with SNMP, which is a related party (see Note 4, "Acquisitions and Divestitures").

Carnero Processing Disposition

On November 22, 2016, we sold our membership interests in Carnero Processing, LLC ("Carnero Processing") to SNMP, which is a related party (see Note 17, "Investments").

SNMP Unit Acquisition

On November 22, 2016, a subsidiary of the Company purchased 2,272,727 common units of SNMP, which is a related party, for $25.0 million in a private placement (see Note 17, "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 is 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.

Carnero Gathering Disposition

On July 5, 2016, we sold our membership interests in Carnero Gathering, LLC ("Carnero Gathering") to SNMP, which is a related party (see Note 17, "Investments").

Palmetto Disposition

On March 31, 2015, we completed the Palmetto Disposition previously discussed with a subsidiary of SNMP, which is a related party (see Note 4, "Acquisitions and Divestitures").

Western Catarina Midstream Divestiture

On October 14, 2015, we completed the Western Catarina Midstream Divestiture previously discussed with SNMP, which is a related party (see Note 4, "Acquisitions and Divestitures").

SR Settlement

On August 11, 2017, the Company, the plaintiffs and all named defendants entered into a Stipulation of Settlement (the "Stipulation") reflecting the terms of the settlement of the derivative stockholder litigation entitled *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. On November 6, 2017, the Stipulation was approved by the Court and became final on December 20, 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 6, "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 12,500 net acres in the TMS. 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:

Proved oil and natural gas properties	$ 17,719
Unproved properties	5,227
Other assets acquired	3,952
Fair value of assets acquired	26,898
Asset retirement obligations	(2,902)
Fair value of net assets acquired	$ 23,996

Comanche Acquisition

On March 1, 2017, we closed the Comanche Acquisition previously discussed and, in connection with the closing, entered into a number of transactions with Gavilan, GSO and the Blackstone Warrantholders, or their affiliates, which are related parties (see Note 4, "Acquisitions and Divestitures"), including (i) the SPA with an investment vehicle owned by the GSO Funds and a controlled affiliate of GSO, (ii) warrant agreements with the Blackstone Warrantholders, (iii) Registration Rights Agreements with the Blackstone Warrantholders and GSO, (iv) the Partnership Agreement with an entity controlled by an affiliate of GSO, and (v) the GP LLC Agreement with a controlled affiliate of GSO (see Note 7, "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, a wholly owned subsidiary of the Company, 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.

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 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.

Note 11. 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 (as defined in Note 20, "Subsequent Events"), the SN UnSub Credit Agreement and the terms of SN UnSub's organizational documents, or were governed by our prior revolving credit facility, 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 our prior revolving credit facility or 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. In connection with the closing of the Comanche Acquisition, we hedged a portion of projected future production attributable to the SN Comanche Assets, using hedge transactions that are consistent with our current hedging strategy.

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 December 31, 2017:

	2018	2019	2020
Oil positions:			
Fixed-for-floating price swaps (NYMEX WTI):			
Hedged volume (Bbls)	8,121,124	3,149,000	381,000
Average price ($/Bbl)	$ 52.45	$ 51.91	$ 53.52
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)	68,818,146	17,644,000	2,361,000
Average price ($/MMBtu)	$ 3.04	$ 2.90	$ 2.82

The following table sets forth a reconciliation of the changes in fair value of the Company's commodity derivatives for the years ended December 31, 2017, 2016, and 2015 (in thousands):

	Year Ended December 31,		
	2017	2016	2015
Beginning fair value of commodity derivatives	$ (35,014)	$ 178,283	$ 123,316
Net gains (losses) on crude oil derivatives	(48,966)	(47,389)	170,592
Net gains (losses) on natural gas derivatives	42,764	(30,307)	26,843
Net settlements on derivative contracts:			
Crude oil	(11,807)	(135,491)	(123,946)
Natural gas	(1,232)	(24,657)	(18,522)
Net premiums on derivative contracts:			
Crude oil	—	24,547	—
Ending fair value of commodity derivatives	$ (54,255)	$ (35,014)	$ 178,283

Embedded Derivatives

In 2017, the Company has entered into contracts for the purchase of sand and coiled tubing that contain provisions that must be bifurcated from the contract and valued as derivatives. The embedded derivatives are valued using a Monte Carlo 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 December 31, 2017, and incurred an approximate $1.6 million loss for the year ended December 31, 2017 as a result. Any gains or losses related to embedded derivatives are recorded as a component of other income (expense) in the consolidated statement of operations.

The following table sets forth a reconciliation of the changes in fair value of the Company's embedded derivatives for the year ended December 31, 2017 (in thousands):

	December 31, 2017
Beginning fair value of embedded derivatives	$ —
Initial fair value of embedded derivatives	—
Loss on embedded derivatives	(1,551)
Ending fair value of embedded derivatives	$ (1,551)

Balance Sheet Presentation

The Company nets derivative assets and liabilities by commodity for counterparties where legal right to such netting 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 netting the derivative assets and liabilities on the Company's condensed consolidated balance sheets (in thousands):

	December 31, 2017		
	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	$ 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	$ 56,269	$ (80)	$ 56,190
Long-term liability	18,145	(672)	17,474
Total liability	$ 74,415	$ (752)	$ 73,664

	December 31, 2016		
	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	$ 844	$ (844)	$ —
Long-term asset	1,426	(1,426)	—
Total asset	$ 2,270	$ (2,270)	$ —
Offsetting Derivative Liabilities:			
Current liability	$ 32,622	$ (844)	$ 31,778
Long-term liability	4,662	(1,426)	3,236
Total liability	$ 37,284	$ (2,270)	$ 35,014

Note 12. Fair Value of Financial Instruments

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

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

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

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

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

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 December 31, 2017 and 2016 (in thousands):

	As of December 31, 2017			
	Active Market for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Total Carrying Value
Cash and cash equivalents:				
Money market funds	$ 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
Embedded derivative instruments:				
Sand and coiled tubing contracts	—	(1,551)	—	(1,551)
Total	$ 80,253	$ (55,806)	$ —	$ 24,447

	As of December 31, 2016			
	Active Market for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Total Carrying Value
Cash and cash equivalents:				
Money market funds	$ 443,648	$ —	$ —	$ 443,648
Equity investment:				
Investment in SNMP	26,818	—	—	26,818
Oil derivative instruments:				
Swaps	—	(8,291)	—	(8,291)
Enhanced Swaps	—	—	—	—
Three-way collars	—	—	—	—
Collars	—	(572)	—	(572)
Puts	—	—	—	—
Gas derivative instruments:				
Swaps	—	(26,151)	—	(26,151)
Total	$ 470,466	$ (35,014)	$ —	$ 435,452

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 consolidated balance sheets as of December 31, 2017 and 2016. 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 the money market funds have daily liquidity, quoted prices for the underlying investments can be obtained and there are active markets for the underlying investments. In addition, the Level 1 instruments include the Company's equity investment in common units of SNMP as further discussed in Note 17, "Investments." The investment in SNMP is being accounting for under the fair value option, included in investments on the Company's balance sheet as of 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 easily obtained. The Level 1 instruments also include the Company's investment in the common shares of Lonestar as further discussed in Note 17, "Investments." The investment in the Lonestar common shares is being accounted for at fair value and included in investments on the Company's balance sheet as of 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.

The Company's derivative instruments consist of swaps, call swaptions, and collars as of December 31, 2017 and 2016. The fair values of the Company's derivatives are based on third-party pricing models which utilize inputs that are either readily available in the public market, such as forward curves, or can be corroborated from active markets of broker quotes. Swaps and collars generally have 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 December 31, 2017, the Company believes that substantially all of the inputs required to calculate the fair value of swaps, call swaptions, and collars are observable in the marketplace throughout the term of these derivative instruments or supported by observable levels at which transactions are executed in the marketplace, and are, therefore, classified as Level 2. As of December 31, 2016, 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 derivative instruments classified as Level 3 as of December 31, 2017 or December 31, 2016.

Embedded Derivatives: The Company consummated contracts for the purchase of sand and coiled tubing that contain provisions that must be bifurcated from the contract and valued as a derivative. The embedded derivatives are valued using a Monte Carlo model which utilizes observable inputs, including the NYMEX WTI oil price and the NYMEX Henry Hub natural gas price at various points in time. 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. The Company has marked these derivatives to market as of December 31, 2017, and incurred an approximate $1.6 million loss as a result. The loss is the result of the decrease in fair value of the embedded derivatives due to the forecasted increase in product costs per terms of the contracts based on an increase in future forecasted oil and natural gas commodity prices.

The fair value of the Company's embedded derivatives classified as Level 2 as of December 31, 2017 was $1.6 million. Changes in the inputs will impact the fair value measurement of the Company's embedded derivative contracts.

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

	(Level 3) Year Ended December 31,		
	2017	2016	2015
Beginning balance	$ —	$ —	$ 75,523
Total gains (losses) included in earnings	—	—	418
Net settlements on derivative contracts(1)	—	—	(14,277)
Derivative contracts transferred to Level 2	—	—	(61,664)
Ending balance	$ —	$ —	$ —
Gains (losses) included in earnings related to derivatives still held as of December 31, 2017, 2016, and 2015	$ —	$ —	$ (940)

(1) Includes ($12,919) of net settlements in Level 2 that were transferred from Level 3 during 2015.

Fair Value on a Non-Recurring Basis

The Company follows the provisions of ASC 820-10 for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. Fair value measurements of assets acquired and liabilities assumed in business combinations are based on inputs that are not observable in the market and thus represent Level 3 inputs. The fair value of acquired properties is based on market and cost approaches. Our purchase price allocation for the 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 13, "Asset Retirement Obligations."

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 10, "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 10, "Related Party Transactions." A reconciliation of the beginning and ending balances of the Company's asset retirement obligations is presented in Note 13, "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 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 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 7, ''Stockholders' and Mezzanine Equity.''

The Company did not record a proved property impairment during the year ended December 31, 2017. For the year ended December 31, 2016, the Company recorded a proved property impairment of $3.7 million to impair the value of our proved oil and natural gas properties in the TMS. The carrying values of the impaired proved properties were reduced to a fair value of $3.3 million, estimated using inputs characteristic of a Level 3 fair value measurement.

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 are traded in an active market, and as such, are classified as Level 1 financial instruments. The estimated fair value of the 7.75% Notes was $567.0 million as of December 31, 2017, and was calculated using quoted market prices based on trades of such debt as of that date. The registered 6.125% Notes are traded in an active market, and as such, are classified as Level 1 financial instruments. The estimated fair value of the 6.125% Notes was $974.6 million as of December 31, 2017 and was calculated using quoted market prices based on trades of such debt as of that date.

Note 13. 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.

The changes in the asset retirement obligation for the years ended December 31, 2017 and 2016 (in thousands) were as follows:

	As of December 31,	
	2017	2016
Abandonment liability as of January 1,	$ 25,087	$ 25,907
Liabilities incurred during period	4,968	1,492
Acquisitions	8,289	219
Divestitures	(3,538)	(4,433)
Revisions	(1,343)	(172)
Accretion expense	2,635	2,074
Abandonment liability as of December 31,	$ 36,098	$ 25,087

Note 14. Accrued Liabilities and Other Current Liabilities

The following information summarizes accrued liabilities as of December 31, 2017 and 2016 (in thousands):

	As of December 31,	
	2017	2016
Capital expenditures	$ 85,340	$ 35,154
Other:		
General and administrative costs	8,855	14,738
Production taxes	5,084	2,396
Ad valorem taxes	84	2,756
Lease operating expenses	32,152	23,942
Interest payable	34,632	34,266
Preferred stock dividends and other	3,987	4,360
Total accrued liabilities	$ 170,134	$ 117,612

The following information summarizes the other payables as of December 31, 2017 and 2016 (in thousands):

	December 31,	
	2017	2016
Revenue payable	$ 75,832	$ 2,124
Production tax payable	2,774	—
Other	3,364	127
Total other payables	$ 81,970	$ 2,251

The following information summarizes the other current liabilities as of December 31, 2017 and 2016 (in thousands):

	December 31,	
	2017	2016
Operated prepayment liability	$ 88,999	$ —
Deferred gain on Western Catarina Midstream Divestiture - short term	23,720	23,720
Phantom compensation payable - short term	2,525	7,388
Total other current liabilities	$ 115,244	$ 31,108

Note 15. Commitments and Contingencies

Litigation

On December 4, 2013, and December 16, 2013, three derivative actions were filed in the Court against the Company, certain of its officers and directors, Sanchez Resources, Altpoint Capital Partners LLC and Altpoint Sanchez Holdings, LLC (Friedman v. A.R. Sanchez, Jr. et al., No. 9158; City of Roseville Employees' Retirement System v. A.R. Sanchez, Jr. et al., No. 9132; and Delaware County Employees Retirement Fund v. A.R. Sanchez, Jr. et al., No. 9165 (collectively, the "Consolidated Derivative Actions")).

On December 20, 2013, the Consolidated Derivative Actions were consolidated, co-lead counsel for the plaintiffs was appointed and the plaintiffs were ordered to file an amended consolidated complaint (In re Sanchez Energy Derivative Litigation, Consolidated C.A. No. 9132-VCG, hereinafter, the "Delaware Derivative Action"). On January 28, 2014, a verified consolidated stockholder derivative complaint was filed. The Consolidated Derivative Actions concern the Company's purchase of working interests in the TMS from SR Acquisition I, LLC ("SR"). Plaintiffs alleged breaches of fiduciary duty against the individual defendants as directors of the Company; breaches of fiduciary duty against Antonio R. Sanchez, III as an executive director of the Company; aiding and abetting breaches of fiduciary duty against SR, Eduardo Sanchez, Altpoint Capital Partners LLC and Altpoint Sanchez Holdings, LLC; and unjust enrichment against A.R. Sanchez, Jr. and Antonio R. Sanchez, III. All of the defendants filed a motion to dismiss on April 1, 2014, which was granted by the Court on November 25, 2014. On October 2, 2015, the Delaware Supreme Court reversed the motions to dismiss and remanded the case to the Court for further proceedings. A mediation in connection with the matter was held on July 7, 2016. A second mediation in connection with the matter was held on June 13, 2017. On August 11, 2017, the Company, the plaintiffs and all named defendants entered into the Stipulation reflecting the terms of the settlement of the Delaware Derivative Action. While the defendants continue to deny each of the plaintiffs' claims and expressly deny any fault, wrongdoing or liability, the defendants agreed to the settlement solely to resolve the disputes, to avoid the costs and risks of further litigation and to avoid further distraction to the Company's management. The litigation was settled, subject to the approval of the Court and in consideration of, among other things, the following: (i) a payment to the Company of an aggregate of $11.75 million ($5.2 million, net of fees, expenses and other amounts), (ii) the transfer of the equity of Sanchez Resources and certain related royalty interests in any TMS acreage to the Company, and (iii) the removal of Alan Jackson and Greg Colvin from the Company's compensation committee. The Stipulation was filed with the Court on August 14, 2017, and a hearing on the settlement was held on November 6, 2017 in the Court. The Court approved the Stipulation and dismissed the Consolidated Derivative Actions with prejudice on November 6, 2017. The terms of the Stipulation became final on December 20, 2017. See Note 10, "Related Party Transactions."

On January 9, 2014, a derivative action was filed in 333rd district court in Harris County, Texas against the Company and certain of its officers and directors, styled Martin v. Sanchez, No. 2014-01028 (333rd Dist. Harris County, Texas). The complaint alleged a breach of fiduciary duty, corporate waste and unjust enrichment against various officers and directors. No action has been taken to date and damages are unspecified. On March 14, 2014, this action was stayed following a ruling on the motion to dismiss in the Delaware Derivative Action. After the motions to dismiss were granted in the Delaware Derivative Action, the parties entered into another agreed stay pending the appeal of the Delaware Derivative Action to the Delaware Supreme Court. This stay was entered by the court on February 5, 2015. The action was dismissed on November 17, 2017.

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.

Lease Payment Obligations

As of December 31, 2017, the Company had $185.7 million in lease payment obligations that satisfy operating lease criteria. These obligations include: (i) $99.6 million in payments due with respect to firm commitment of oil and natural gas volumes under the Gathering Agreement relating to the Western Catarina Midstream Divestiture that commenced on October 14, 2015 and continues until October 13, 2020, (ii) $81.1 million for a corporate office lease that commenced in the fourth quarter of 2014 and has an expiration date in December 2025, and (iii) $5.0 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 December 31, 2017, the Company had approximately $561.5 million in future commitments related to oil and natural gas gathering and transportation agreements ($222.3 million for 2018 through 2020, $175.6 million from 2021 through 2023, and $163.6 million under commitments expiring after December 31, 2023, in the aggregate) and approximately $179.5 million in future commitments related to natural gas processing agreements ($85.9 million for 2018 through 2020, $31.6 million from 2021 through 2023, and $62.0 expiring after December 31, 2023) that are not recorded in the accompanying consolidated balance sheets.

For the year ended December 31, 2017, the Company incurred expenses related to deficiency fees of approximately $4.8 million that are reported on the consolidated statements of operations in the "Oil and natural gas production expenses" line item. We do not anticipate that any future deficiency payments under these contracts would be material, and expect to fulfill these obligations in the future based on the applicable anticipated development plan.

Note 16. Subsidiary Guarantors

The Company filed registration statements on Form S-3 with the SEC, which became effective January 14, 2013, June 11, 2014 and April 25, 2016 and registered, among other securities, debt securities. The subsidiaries of the Company named therein are co-registrants with the Company, and the registration statement registered guarantees of debt securities by such subsidiaries. As of December 31, 2017, such subsidiaries are 100 percent owned by the Company and any guarantees by these subsidiaries will be full and unconditional (except for customary release provisions). In the event that more than one of these subsidiaries provide guarantees of any debt securities issued by the Company, such guarantees will constitute joint and several obligations.

The Company also filed a registration statement on Form S-4 with the SEC, which became effective on June 20, 2014, pursuant to which the Company completed an offering of the 7.75% Notes, which are guaranteed by its subsidiaries named therein. As of December 31, 2017, such guarantor subsidiaries are 100 percent owned by the Company and the guarantees by these subsidiaries are full and unconditional (except for customary release provisions) and are joint and several. The Company also filed a registration statement on Form S-4 with the SEC, which became effective on January 23, 2015, pursuant to which the Company completed an offering of the 6.125% Notes, which are guaranteed by its subsidiaries named therein. As of December 31, 2017, such guarantor subsidiaries are 100 percent owned by the Company and the guarantees by these subsidiaries are full and unconditional (except for customary release provisions) and are joint and several.

The Company's 7.75% Notes and 6.125% Notes 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 LLC, SR, SR Acquisition III, LLC and SR TMS, LLC which are unrestricted subsidiaries of the Company.

The rules of Regulation S-X Rule 3-10 require that condensed consolidating financial information be provided for a subsidiary that has guaranteed the debt of a registrant issued in a public offering, where the guarantee is full, unconditional and joint and several and where the voting interest of the subsidiary is 100% owned by the registrant. See Note 19, "Condensed Consolidating Financial Information" for further discussion regarding the condensed consolidating financial information for guarantor and non-guarantor subsidiaries.

The Company has no assets or operations independent of its subsidiaries and there are no significant restrictions upon the ability of its subsidiaries to distribute funds to the Company, except as noted below. SN UnSub's and SN UnSub General Partner's ability to distribute funds to the Company or its subsidiaries by dividend or loan is restricted by (i) the restrictive or negative covenants in the SN UnSub Credit Agreement, (ii) the terms of the SN UnSub Preferred Units and (iii) the consent or approval rights of the GSO Funds (or their representatives or affiliates) under the Partnership Agreement and the GP LLC Agreement, as the case may be (see "Note 6. Debt—SN UnSub Credit Agreement" and "Note 7. Stockholders' and Mezzanine Equity—SN UnSub Preferred Units Issuance"). 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.

Note 17. 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 December 31, 2017, this ownership represents approximately 6.1% of Lonestar's outstanding shares of common stock. The investment in Lonestar accounted for by the Company as investments in equity securities measured at fair value in the consolidated balance sheets at the end of each reporting period. The Company recorded losses related to the investment in Lonestar for the year ended December 31, 2017 of less than $0.1 million. Any gains or losses related to the investment in Lonestar are recorded as a component of other income (expense) in the 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 had invested $12.5 million in the SOII Facility. No gain or loss was recorded on the SOII Disposition. The Company recorded earnings of approximately $779 thousand from its equity interest in the SOII Facility for the period from March 1, 2017 through June 1, 2017, the effective date of the transaction.

On March 1, 2017, pursuant to the LLC Agreement of GRHL, GRHL authorized and issued a total of 100 Class A Units to SN Comanche Manager, a wholly owned unrestricted subsidiary of the Company. 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 December 31, 2017, 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 December 31, 2017. The Company did not record any earnings from its ownership of the Class A Units for the period from January 1, 2017 through December 31, 2017.

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. As of December 31, 2017, this ownership represents approximately 15.2% 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. Any gains or losses and dividend income related to the investment in SNMP are recorded as a component of other income (expense) in the consolidated statement of operations. The Company recorded losses related to the investment in SNMP for the twelve months ended December 31, 2017 of approximately $1.6 million.

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 are estimated at approximately $24.5 million (the "Carnero Processing Disposition"). The Company was accounting for this joint venture as an equity method investment as Targa is the operator of the joint venture and has the most influence with respect to the normal day-to-day construction and operating decisions. Prior to the sale, the Company had invested approximately $48.0 million in Carnero Processing joint venture. The membership interests disposed of constitute 50% of the outstanding membership interests in Carnero Processing. The remaining 50% membership interests of Carnero Processing are owned by an affiliate of Targa. Prior to the sale of Carnero Processing, the Company recorded losses of approximately $0.1 million from equity investments during 2016. The Company recorded a deferred gain of approximately $7.5 million included in "Other Liabilities" as a result of the firm gas processing agreement that remains between the Company and Targa. This deferred gain was to be amortized over the term of this firm gas processing agreement according to volumes processed through the Carnero Processing facility, however, upon adoption of ASC 606, this deferred gain will be reversed and opening retained earnings will be adjusted as of January 1, 2018.

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"). The Company was accounting for this joint venture as an equity method investment as Targa is the operator of the joint ventures and has the most influence with respect to the normal day-to-day construction and operating decisions. Prior to the sale, the Company had invested approximately $26.0 million in Carnero Gathering joint venture. As part of the Carnero Gathering Disposition, SNMP is required to pay SN Midstream a monthly “earnout” based on gas received at Carnero Gathering’s Raptor Gas Processing Facility receipt points from SN Catarina and gas delivered and processed at the Raptor Gas Processing Facility by other producers. The membership interests disposed of constitute 50% of the outstanding membership interests in Carnero Gathering. The remaining 50% membership interests of Carnero Gathering are owned by an affiliate of Targa. Prior to the sale of Carnero Gathering, the Company recorded earnings of approximately $2.3 million from equity investments during 2016. The Company recorded a deferred gain of approximately $8.7 million included in “Other Liabilities” as a result of the firm gas gathering agreement that remains between the Company and Targa and a transportation services agreement between Targa and Carnero Gathering. This deferred gain was to be amortized over the term of this firm gas gathering agreement according to volumes processed through the Carnero Processing facility, however, upon adoption of ASC 606, this deferred gain will be reversed and opening retained earnings will be adjusted as of January 1, 2018. Additionally, the adoption will result in the “earnout” being considered a derivative asset that will be revalued quarterly.

On October 2, 2015, the Company, via SN Catarina, purchased from a subsidiary of Targa a 10% undivided interest in the Silver Oak II Gas Processing Facility (the “SOII Facility”) in Bee County, Texas for a purchase price of $12.5 million. Targa owned the remaining undivided 90% interest in the SOII Facility, which is operated by Targa. Concurrently with the execution of the purchase and sale agreement for the SOII Facility, the Company entered into a firm gas processing agreement, whereby Targa would process a firm quantity, 125,000 Mcf/d, until the in-service date of Carnero Processing’s Raptor Gas Processing Facility. The Company accounted for the investment in the SOII Facility as an equity method investment as Targa is the operator and majority interest owner of the SOII Facility. As of December 31, 2016, the Company had invested capital of $12.5 million in the SOII Facility. The Company recorded earnings from the SOII Facility investment of approximately $1.2 million from equity investments during 2016.

Note 18. Variable Interest Entities

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

As noted previously in Note 17, “Investments,” pursuant to the LLC Agreement of GRHL, GRHL authorized and issued a total of 100 Class A Units to SN Comanche Manager, a wholly owned unrestricted subsidiary of the Company. 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 December 31, 2017, was approximately $7.3 million. The Company did not record any earnings from its ownership of the Class A Units for the period from March 1, 2017 through December 31, 2017. 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 previously in Note 17, “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 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 cannot remove Targa as operator and we do not have substantive participating rights. In addition, Targa has the discretion to direct activities of the VIEs regarding the risks associated with price, operations, and capital investment which have the most significant impact on the VIEs economic performance.

The Company 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 previously in Note 17, “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 December 31, 2017, was approximately $25.2 million.

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 December 31, 2017 and December 31, 2016 (in thousands):

	December 31, 2017	December 31, 2016
Beginning Balance	$ 39,656	$ 37,527
Investment in GRHL	7,280	—
Earnings on (distributions from) equity investments	(311)	311
Gain (Loss) from change in fair value of investment in SNMP	(1,591)	1,818
Sale of investments	(12,527)	—
Equity in equity investments	$ 32,507	$ 39,656

	December 31, 2017	December 31, 2016
Equity in equity investments	$ 32,507	$ 39,656
Guarantees of capital investments	—	—
Maximum exposure to loss	$ 32,507	$ 39,656

Note 19. Condensed Consolidating Financial Information

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

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

Sanchez Energy Corporation

Notes to the Consolidated Financial Statements (Continued)

A summary of the condensed consolidated guarantor balance sheets for the periods ended December 31, 2017 and December 31, 2016 (in thousands) is presented below:

	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

	December 31, 2016				
Assets	**Parent Company**	**Combined Guarantor Subsidiaries**	**Combined Non-Guarantor Subsidiaries**	**Eliminations**	**Consolidated**
Total current assets	$ 428,384	$ 123,380	$ 158,589	$ (147,548)	$ 562,805
Total oil and natural gas properties, net	—	704,519	—	—	704,519
Investment in subsidiaries	734,704	—	—	(734,704)	—
Other assets	14,376	15,221	35,290	—	64,887
Total Assets	$ 1,177,464	$ 843,120	$ 193,879	$ (882,252)	$ 1,332,211
Liabilities and Shareholders' Equity					
Current liabilities	$ 84,673	$ 78,344	$ 170,435	$ (147,548)	$ 185,904
Long-term liabilities	1,788,930	25,086	16,273	—	1,830,289
Total shareholders' equity (deficit)	(696,139)	739,690	7,171	(734,704)	(683,982)
Total Liabilities and Shareholders' Equity (deficit)	$ 1,177,464	$ 843,120	$ 193,879	$ (882,252)	$ 1,332,211

Sanchez Energy Corporation

Notes to the Consolidated Financial Statements (Continued)

A summary of the condensed consolidated guarantor statements of operations for the periods ended December 31, 2017, December 31, 2016, and December 31, 2015 (in thousands) is presented below:

	Year Ended December 31, 2017				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$ —	$ 509,701	$ 230,630	$ —	$ 740,331
Total operating costs and expenses	(92,008)	(387,614)	(168,942)	680	(647,884)
Other income (expense)	(121,603)	75,837	(5,145)	(680)	(51,591)
Income (loss) before income taxes	(213,611)	197,924	56,543	—	40,856
Income tax benefit	2,336	—	—	—	2,336
Equity in income (loss) of subsidiaries	193,376	—	—	(193,376)	—
Net income (loss)	$ (17,899)	$ 197,924	$ 56,543	$ (193,376)	$ 43,192

	Year Ended December 31, 2016				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$ —	$ 431,326	$ —	$ —	$ 431,326
Total operating costs and expenses	(111,155)	(367,541)	(1,947)	—	(480,643)
Other income (expense)	(177,710)	82,948	4,418	—	(90,344)
Loss before income taxes	(288,865)	146,733	2,471	—	(139,661)
Income tax expense	(1,825)	—	—	—	(1,825)
Equity in income (loss) of subsidiaries	33,730	—	—	(33,730)	—
Net income (loss)	$ (256,960)	$ 146,733	$ 2,471	$ (33,730)	$ (141,486)

	Year Ended December 31, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$ —	$ 475,779	$ —	$ —	$ 475,779
Total operating costs and expenses	(75,096)	(1,169,246)	(1,692)	—	(1,246,034)
Other income (expense)	44,726	(402)	—	—	44,324
Loss before income taxes	(30,370)	(693,869)	(1,692)	—	(725,931)
Income tax benefit	(158)	—	—	—	(158)
Equity in income (loss) of subsidiaries	(1,416,657)	—	—	1,416,657	—
Net income (loss)	$ (1,447,185)	$ (693,869)	$ (1,692)	$ 1,416,657	$ (726,089)

Sanchez Energy Corporation

Notes to the Consolidated Financial Statements (Continued)

A summary of the condensed consolidated guarantor statements of cash flows for the periods ended December 31, 2017, December 31, 2016, and December 31, 2015 (in thousands) is presented below:

	Year Ended December 31, 2017				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ (148,259)	$ 346,345	$ 94,003	$ —	$ 292,089
Net cash provided by (used in) investing activities	(266,135)	(620,382)	(760,909)	264,626	(1,382,800)
Net cash provided by (used in) financing activities	157,390	303,083	577,381	(264,626)	773,228
Net increase (decrease) in cash and cash equivalents	(257,004)	29,046	(89,525)	—	(317,483)
Cash and cash equivalents, beginning of period	343,941	—	157,976	—	501,917
Cash and cash equivalents, end of period	$ 86,937	$ 29,046	$ 68,451	$ —	$ 184,434

	Year Ended December 31, 2016				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ (36,741)	$ 218,864	$ 631	$ —	$ 182,754
Net cash provided by (used in) investing activities	(46,602)	(133,412)	55,571	16,209	(108,234)
Net cash provided by (used in) financing activities	(7,650)	(85,452)	101,660	(16,209)	(7,651)
Net increase (decrease) in cash and cash equivalents	(90,993)	—	157,862	—	66,869
Cash and cash equivalents, beginning of period	434,934	—	114	—	435,048
Cash and cash equivalents, end of period	$ 343,941	$ —	$ 157,976	$ —	$ 501,917

	Year Ended December 31, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ (43,556)	$ 315,516	$ (1,384)	$ —	$ 270,576
Net cash provided by (used in) investing activities	21,670	(247,202)	(40,327)	(26,490)	(292,349)
Net cash provided by (used in) financing activities	(16,894)	(68,314)	41,825	26,490	(16,893)
Net increase (decrease) in cash and cash equivalents	(38,780)	—	114	—	(38,666)
Cash and cash equivalents, beginning of period	473,714	—	—	—	473,714
Cash and cash equivalents, end of period	$ 434,934	$ —	$ 114	$ —	$ 435,048

Note 20. Subsequent Events

On January 2, 2018, dividends declared by our Board and accrued for the period from October 1 to December 31, 2017 for the Series A Preferred Stock and Series B Preferred Stock were paid in shares of the Company's common stock.

Indenture and 7.25% Senior Notes

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 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 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 (as defined below). 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. These covenants are subject to a number of important qualifications and limitations, and the Company's unrestricted subsidiaries (including SN EF UnSub, LP) will not be subject to these covenants. Many of the covenants in the Indenture will be terminated if at any time no default (other than a reporting default) exists under the Indenture and the 7.25% Senior Secured Notes receive an investment grade rating from both of two specified ratings agencies.

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 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 gas properties with no proved reserves, equity interests in SN UnSub and other existing and future subsidiaries designated as "unrestricted subsidiaries."

The Indenture provides that each of the following is an event of default: (i) default for 30 days in the payment when due of interest on the 7.25% Senior Secured Notes; (ii) default in payment when due (at stated maturity, upon redemption, acceleration or otherwise) of the principal of, or premium, if any, on, the 7.25% Senior Secured Notes; (iii) failure by the Company to comply with certain covenants relating to merger, consolidation, sale of all or substantially all assets or change of control; (iv) failure by the Company for 30 days after notice to comply with certain obligations to repurchase 7.25% Senior Secured Notes from the proceeds of certain asset sales; (v) failure by the Company for 180 days after notice to comply with its reporting obligations; (vi) failure by the Company for 60 days after notice to comply with any of the other agreements in the Indenture; (vii) there occurs with respect to any indebtedness having an outstanding principal amount of $40 million or more of the Company or any of its restricted subsidiaries (a) an event of default which results in such indebtedness being due and payable prior to its express maturity or (b) failure to make a principal, premium or interest payment when due and such defaulted payment is not made, waived or extended within the applicable grace period; (viii) failure by the Company or any of its restricted subsidiaries to pay final judgments aggregating in excess of $40 million, which judgments are not paid, discharged or stayed for a period of 60 days; (ix) certain events of bankruptcy or insolvency described in the Indenture with respect to the Company or any of the Company's significant subsidiaries; (x) any guarantee ceases to be in full force and effect, other than in accordance with the terms of the Indenture, or a guarantor of the 7.25% Senior Secured Notes denies or disaffirms its obligations under its guarantee; (xi) any priority lien with value in excess of $50 million ceases to be enforceable, and such failure continues uncured for 45 days after any officer of the Company or any restricted subsidiary becomes aware of such failure; (xii) any priority lien with value in excess of $50 million ceases to be an enforceable and perfected first-priority lien, and such failure continues uncured for 45 days after any officer of the Company or any restricted subsidiary becomes aware of such failure; and (xiii) the Company or any other grantor denies or disaffirms any obligation of the Company or any other grantor set forth under any priority lien document establishing priority liens. In the case of an event of default arising from certain events of bankruptcy or insolvency with respect to the Company or the Company's significant subsidiaries, all outstanding 7.25% Senior Secured Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding 7.25% Senior Secured Notes may declare all the 7.25% Senior Secured Notes to be due and payable immediately.

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 as the administrative agent and collateral agent, RBC Capital Markets as the Arranger and the lenders party thereto, 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 existing credit facility in its entirety. Availability under the 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.

The Credit Agreement will mature on the earlier of (i) February 14, 2023 and (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, are secured by priority liens on a first-out collateral proceeds payment priority basis in the Shared Collateral referred to above, subject only to permitted collateral liens.

As a condition precedent to the issuance of loans or letters of credit under the Credit Agreement when there are no loans or letters of credit currently outstanding, the Company must demonstrate that the PDP Coverage Ratio is no less than 4.00 to 1.00. "PDP Coverage Ratio" means the then-applicable ratio of (i) (a) the Loan Parties' proved developed producing properties' PV-10 value, (b) the net mark-to-market value of commodity swaps in effect as of the date of calculation, plus (c) unrestricted cash on hand of the Loan Parties to (ii) the Credit Agreement commitment amount (initially $25,000,000). The Credit Agreement: (x) requires the PDP Coverage Ratio to be calculated (i) following any disposition by a Loan Party to a non-Loan Party of any proved developed producing properties that were included in the most recent reserve report delivered to the collateral agent that had a PV-10 value in excess of $10,000,000 in such reserve report, (ii) as of the end of each fiscal quarter of the Company if any loans or letters of credit under the Credit Agreement are outstanding at such time, and (iii) at the time of certain proposed restricted payments under the Credit Agreement; (y) to the extent at the time of any calculation specified in clause (x)(i) or (ii) the PDP Coverage Ratio is less than 4.00 to 1.00, requires a reduction in the commitment thereunder, together with any mandatory repayment of outstanding loans or cash collateralization of outstanding letters of credit to the extent necessary to increase the PDP Coverage Ratio to at least 4.00 to 1.00; and (z) prohibits any such restricted payments unless the PDP Coverage Ratio after giving effect to such restricted payment on a pro forma basis is at the time at least 4.00 to 1.00.

At the Company's election, interest on borrowings under the Credit Agreement may be calculated based on an alternate base rate ("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.

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.

Marquis Disposition

On November 7, 2017, Lonestar filed a registration statement on Form S-3 registering, among other things, the resale of the 1.5 million shares of Class A Common Stock held by the Company to comply with Lonestar's obligations under a registration rights agreement with the Company. The registration statement was amended by Lonestar on February 14, 2018. On February 22, 2018, the registration statement was declared effective by the SEC.

Sanchez Energy Corporation

Supplementary Quarterly Financial Results (Unaudited)

Net income (loss) attributable to common stockholders

The following table presents the Company's unaudited quarterly financial information for 2017 and 2016 (in thousands, except per share amounts). During the fourth quarter of 2017, the Company changed its method of accounting for its oil and gas exploration and development activities from full cost to the successful efforts method of accounting. Because this change in accounting principle is required to be applied retroactively, financial information for the third quarter of 2017 and prior periods presented in the tables below have been revised.

2017, under Successful Efforts:	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
Oil and natural gas revenue	$ 133,843	$ 175,704	$ 184,806	$ 245,978
Impairment of oil and natural gas properties	(1,845)	29	(740)	(37,018)
Operating costs and expenses	(138,743)	(146,450)	(144,230)	(178,887)
Operating income (loss)	(6,745)	29,283	39,836	30,073
Interest income	357	150	163	166
Other income (expense)	10,535	(6,618)	1,537	5,648
Gain (loss) on sale of oil and natural gas properties	4,344	6,022	71,589	—
Interest expense	(33,025)	(35,961)	(35,686)	(35,491)
Earnings from Equity Investments	435	242	102	—
Net gains (losses) on commodity derivatives	38,881	59,615	(41,719)	(62,877)
Other income (expense), net	21,527	23,450	(4,014)	(92,554)
Income (loss) before income taxes	14,782	52,733	35,822	(62,481)
Income tax benefit (expense)	953	255	—	1,128
Net income (loss)	15,735	52,988	35,822	(61,353)
Less:				
Preferred stock dividends	(3,987)	(3,987)	(3,988)	(3,986)
Preferred unit dividends and distributions	(16,466)	(10,949)	(8,347)	(8,497)
Preferred unit amortization	(1,710)	(5,282)	(5,517)	(5,530)
Net income allocable to participating securities (1) (2)	—	(2,378)	(1,230)	—
Net income (loss) attributable to common stockholders	$ (6,428)	$ 30,392	$ 16,740	$ (79,366)
Basic income (loss) per share (3)	$ (0.09)	$ 0.40	$ 0.22	(1.01)
Weighted average common shares outstanding - basic	69,659	76,395	77,453	78,804
Diluted income (loss) per share (3)	$ (0.09)	$ 0.39	$ 0.22	$ (1.01)
Weighted average common shares outstanding - diluted	69,659	89,015	77,553	78,804

(1) No losses are allocated to participating restricted stock. Such securities do not have a contractual obligation to share in the Company's losses.

(2) The sum of quarterly net income allocable to participating securities will not agree with total year net income allocable to participating securities as each quarterly computation is based on the allocation of net income for the quarter to the participating securities.

(3) The sum of quarterly net income per share may not agree with total year net income per share as each quarterly computation is based on the allocation of net income for the quarter to the participating securities and the weighted average shares outstanding

2016, under Successful Efforts:	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Oil and natural gas revenue	$ 79,816	$ 110,968	$ 114,807	$ 125,735
Impairment of oil and natural gas properties	(20,982)	(3,734)	(9,058)	(13,606)
Operating costs and expenses	(98,238)	(110,363)	(106,547)	(118,112)
Operating income (loss)	(39,404)	(3,129)	(799)	(5,983)
Interest income	325	158	146	227
Other income (expense)	(414)	211	7	330
Gain on disposal of assets	—	—	—	85,322
Interest expense	(31,606)	(31,822)	(31,797)	(31,748)
Earnings from Equity Investments	512	2,179	463	312
Net gains (losses) on commodity derivatives	22,757	(58,750)	18,640	(35,796)
Other income (expense), net	(8,426)	(88,024)	(12,541)	18,647
Income (loss) before income taxes	(47,830)	(91,153)	(13,340)	12,664
Income tax benefit (expense)	—	—	(1,441)	(384)
Net income (loss)	(47,830)	(91,153)	(14,781)	12,280
Less:				
Preferred stock dividends	(3,987)	(3,987)	(3,987)	(3,987)
Net income allocable to participating securities (1) (2)	—	—	—	(861)
Net income (loss) attributable to common stockholders	$ (51,817)	$ (95,140)	$ (18,768)	$ 7,432
Basic income (loss) per share (3)	$ (0.89)	$ (1.63)	$ (0.32)	0.13
Weighted average common shares outstanding - basic	58,099	58,413	59,190	59,252
Diluted income (loss) per share (3)	$ (0.89)	$ (1.63)	$ (0.32)	$ 0.13
Weighted average common shares outstanding - diluted	58,099	58,413	59,190	59,252

(1) No losses are allocated to participating restricted stock. Such securities do not have a contractual obligation to share in the Company's losses.

(2) The sum of quarterly net income allocable to participating securities will not agree with total year net income allocable to participating securities as each quarterly computation is based on the allocation of net income for the quarter to the participating securities.

(3) The sum of quarterly net income per share may not agree with total year net income per share as each quarterly computation is based on the allocation of net income for the quarter to the participating securities and the weighted average shares outstanding.

The following tables present a summary of the Company's quarterly summarized statements of operations for 2017 and 2016 reported under the full cost method:

2017, under Full Cost:	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
Oil and natural gas revenue	$ 133,843	$ 175,704	$ 184,806	$ 245,979
Impairment of oil and natural gas properties	—	—	—	—
Operating costs and expenses	(147,420)	(154,211)	(149,926)	(181,913)
Operating income (loss)	(13,577)	21,493	34,880	64,066
Interest income	357	150	163	166
Other income (expense)	10,535	(6,618)	(448)	3,883
Gain (loss) on sale of oil and natural gas properties	5,143	7,133	(2,074)	—
Interest expense	(33,025)	(35,961)	(35,686)	(35,492)
Earnings from Equity Investments	435	242	102	—
Net gains (losses) on commodity derivatives	38,881	59,615	(41,719)	(62,877)
Other income (expense), net	22,326	24,561	(79,662)	(94,320)
Income (loss) before income taxes	8,749	46,054	(44,782)	(30,254)
Income tax benefit (expense)	953	255	—	1,129
Net income (loss)	9,702	46,309	(44,782)	(29,125)
Less:				
Preferred stock dividends	(3,987)	(3,987)	(3,988)	(3,987)
Preferred unit dividends and distributions	(16,466)	(10,949)	(8,347)	(8,497)
Preferred unit amortization	(1,710)	(5,282)	(5,517)	(5,530)
Net income allocable to participating securities [(1)] [(2)]	—	(1,893)	—	—
Net income (loss) attributable to common stockholders	$ (12,461)	$ 24,198	$ (62,634)	$ (47,139)
Basic income (loss) per share [(3)]	$ (0.18)	$ 0.32	$ (0.81)	(0.60)
Weighted average common shares outstanding - basic	69,659	76,395	77,453	78,804
Diluted income (loss) per share [(3)]	$ (0.18)	$ 0.31	$ (0.81)	$ (0.60)
Weighted average common shares outstanding - diluted	69,659	89,015	77,453	78,804

(1) No losses are allocated to participating restricted stock. Such securities do not have a contractual obligation to share in the Company's losses.

(2) The sum of quarterly net income allocable to participating securities will not agree with total year net income allocable to participating securities as each quarterly computation is based on the allocation of net income for the quarter to the participating securities.

(3) The sum of quarterly net income per share may not agree with total year net income per share as each quarterly computation is based on the allocation of net income for the quarter to the participating securities and the weighted average shares outstanding.

2016, Under Full Cost:	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Oil and natural gas revenue	$ 79,816	$ 110,968	$ 114,807	$ 125,735
Impairment of oil and natural gas properties	(22,084)	(87,380)	(59,582)	—
Operating costs and expenses	(115,081)	(118,432)	(107,505)	(113,023)
Operating income (loss)	(57,349)	(94,844)	(52,280)	12,712
Interest income	325	158	146	227
Other income (expense)	(414)	211	7	330
Gain (loss) on sale of oil and natural gas properties	—	—	—	112,294
Interest expense	(31,606)	(31,822)	(31,797)	(31,748)
Earnings from Equity Investments	512	2,179	463	312
Net gains (losses) on commodity derivatives	22,757	(58,750)	18,640	(35,796)
Other income (expense), net	(8,426)	(88,024)	(12,541)	45,619
Income (loss) before income taxes	(65,775)	(182,868)	(64,821)	58,331
Income tax benefit (expense)	—	—	(1,441)	(384)
Net income (loss)	(65,775)	(182,868)	(66,262)	57,947
Less:				
Preferred stock dividends	(3,987)	(3,987)	(3,987)	(3,987)
Net income allocable to participating securities [(1) (2)]	—	—	—	(5,601)
Net income (loss) attributable to common stockholders	$ (69,762)	$ (186,855)	$ (70,249)	$ 48,359
Basic income (loss) per share [(3)]	$ (1.20)	$ (3.20)	$ (1.19)	0.82
Weighted average common shares outstanding - basic	58,099	58,413	59,190	59,252
Diluted income (loss) per share [(3)]	$ (1.20)	$ (3.20)	$ (1.19)	$ 0.73
Weighted average common shares outstanding - diluted	58,099	58,413	59,190	71,772

(1) No losses are allocated to participating restricted stock. Such securities do not have a contractual obligation to share in the Company's losses.

(2) The sum of quarterly net income allocable to participating securities will not agree with total year net income allocable to participating securities as each quarterly computation is based on the allocation of net income for the quarter to the participating securities.

(3) The sum of quarterly net income per share may not agree with total year net income per share as each quarterly computation is based on the allocation of net income for the quarter to the participating securities and the weighted average shares outstanding.

Effect of Accounting Change on Fourth Quarter

As the Company recast the financial statements due to a change in accounting principle during the fourth quarter of 2017, the effects of the accounting change on the fourth quarter consolidated statement of operations are included below. Refer to Note 3, "Change in Accounting Principle" for additional details.

	Changes to the Consolidated Statement of Operations		
For the Quarter Ended December 31, 2017	Under Full Cost	Changes	As Reported Under Successful Efforts
	(In thousands, except per share data)		
Oil and natural gas production expenses	$ 76,239	$ (2,227)	$ 74,012
Depreciation, depletion, amortization and accretion	63,171	(799)	62,372
Impairment of oil and natural gas properties	—	37,018	37,018
Other income (expense)	3,883	1,765	5,648
Net loss	(29,125)	(32,227)	(61,352)
Net income allocable to participating securities	—	—	—
Net loss attributable to common stockholders	$ (47,139)	$ (32,227)	$ (79,366)
			—
Net loss per common share - basic and diluted	$ (0.60)	$ (0.41)	$ (1.01)

Sanchez Energy Corporation
Supplemental Information on Oil and Natural Gas Exploration,
Development and Production Activities
(Unaudited)

During the fourth quarter of 2017, the Company changed its method of accounting for its oil and gas exploration and development activities from full cost to the successful efforts method of accounting. Because this change in accounting principle is required to be applied retroactively, financial information for the third quarter of 2017 and prior periods presented in the tables below have been revised.

Capitalized Costs—Capitalized costs and accumulated depreciation, depletion and impairment relating to the Company's oil and natural gas producing activities are summarized below as of the dates indicated (in thousands):

	As of December 31,		
	2017	2016	2015
Oil and Natural Gas Properties:			
Unproved	$ 398,605	$ 225,023	$ 246,598
Proved	3,130,407	1,849,732	1,912,394
Total Oil and Natural Gas Properties	3,529,012	2,074,755	2,158,993
Less Accumulated depreciation, depletion, amortization and impairment	(1,501,553)	(1,370,236)	(1,463,524)
Net oil and natural gas properties capitalized	$ 2,027,459	$ 704,519	$ 695,468

Costs Incurred—Costs incurred in oil and natural gas property acquisition, exploration and development activities are summarized below (in thousands):

	Year Ended December 31,		
	2017	2016	2015
Exploration costs	$ 5,755	$ 379	$ 30,523
Development costs	562,309	284,569	512,208
Acquisition and Divestiture costs:			
Proved properties	326,835	50	—
Unproved properties	733,511	13,430	8,508
Total Costs Incurred	$ 1,628,410	$ 298,428	$ 551,239
Seismic costs included in exploration costs	$ 5,755	$ 379	$ 1,446

Results of Operations—Results of operations for the Company's production of oil, natural gas and NGLs are summarized below (in thousands):

	Year Ended December 31,		
	2017	**2016**	**2015**
Oil, natural gas and natural gas liquids revenue	$ 740,331	$ 431,326	$ 475,779
Less operating expenses:			
Oil, natural gas and natural gas liquids production expenses	(244,461)	(155,660)	(154,672)
Production and ad valorem taxes	(36,615)	(19,633)	(26,870)
Depreciation, depletion, amortization and accretion	(177,078)	(147,485)	(264,379)
Impairment of oil and natural gas properties	(39,574)	(47,381)	(723,971)
Results of operations from oil and gas producing activities	$ 242,603	$ (81,680)	$ (1,417,191)

Reserves—Proved reserves are those quantities of oil, natural gas and NGLs, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well.

Proved undeveloped reserves ("PUDs") are reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of producing economic quantities at a greater distance. Only those undrilled locations that are scheduled to be drilled within five years pursuant to a development plan can be allocated to undeveloped reserves, unless the specific circumstances justify a longer time. As of December 31, 2017, the Company did not have any PUDs previously disclosed that have remained undeveloped for five years or more and no PUD locations included in the Company's proved oil reserves are scheduled to be drilled after five years.

Estimates of proved developed and undeveloped reserves for the periods presented are based on estimates made by the independent engineers, Ryder Scott.

Proved reserves for all periods presented were estimated in accordance with the guidelines established by the SEC and FASB. The rules require SEC reporting companies to prepare their reserve estimates based on the average prices during the 12 month period prior to the ending date of the period covered in the report, determined as the unweighted arithmetic average of the prices in effect on the first day of the month for each month within such period, unless prices were defined by contractual arrangements. The product prices used to determine the future gross revenues for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from the market. The pricing used for the estimates of the Company's reserves of oil and condensate as of December 31, 2017, 2016 and 2015 was based on unweighted twelve month average WTI posted prices of $51.34, $42.75, and $50.28, respectively. The pricing used for the estimates of the Company's reserves of natural gas as of December 31, 2017, 2016 and 2015 were based on an unweighted twelve month average Henry Hub spot natural gas prices average of $2.98, $2.49, and $2.58, respectively. The pricing used for the estimates of the Company's reserves of NGLs as of December 31, 2017, 2016 and 2015 were based on an unweighted twelve month average Mt. Belvieu prices average of $31.82, $19.97, and $19.90, respectively.

Net proved quantities summary

The following table sets forth the net proved, proved developed and proved undeveloped reserves activity for the years ended December 31, 2017, 2016 and 2015:

	Oil (MBbl)	Natural Gas Liquids (MBbl)	Natural Gas (MMcf)	MBoe (1)
Balance as of December 31, 2014	64,534	35,284	209,653	134,760
Revisions of previous estimates	(16,395)	(2,000)	3,427	(17,823)
Extensions and discoveries	14,369	10,091	63,860	35,103
Sales of reserves in place	(3,578)	(824)	(4,871)	(5,213)
Production	(7,165)	(5,754)	(37,594)	(19,184)
Balance as of December 31, 2015	51,765	36,798	234,475	127,643
Revisions of previous estimates	(20,506)	(10,733)	(49,076)	(39,418)
Extensions and discoveries	42,778	39,237	278,715	128,467
Sales of reserves in place	(3,090)	(675)	(3,760)	(4,392)
Production	(6,370)	(5,960)	(43,189)	(19,529)
Balance as of December 31, 2016	64,577	58,667	417,165	192,770
Revisions of previous estimates	(4,778)	(296)	26,146	(715)
Extensions and discoveries	15,920	13,288	93,153	44,733
Purchases of reserves in place	57,063	48,909	292,051	154,647
Sales of reserves in place	(2,155)	(506)	(2,273)	(3,040)
Production	(8,217)	(8,342)	(54,650)	(25,667)
Balance as of December 31, 2017	122,411	111,719	771,593	362,729
Proved developed reserves:				
As of December 31, 2015	21,718	20,803	132,911	64,672
As of December 31, 2016	18,245	21,060	149,029	64,143
As of December 31, 2017	54,514	57,340	384,989	176,018
Proved undeveloped reserves:				
As of December 31, 2015	30,048	15,995	101,564	62,970
As of December 31, 2016	46,332	37,606	268,136	128,627
As of December 31, 2017	67,897	54,380	386,604	186,711

(1) Oil equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of gas to 1.0 Bbl of oil.

Standardized Measure—The standardized measure of discounted future net cash flows relating to the Company's ownership interest in proved reserves of oil, natural gas and NGLs as of December 31, 2017, 2016 and 2015 is shown below (in thousands):

	As of December 31,		
Standardized Measure	2017	2016	2015
Future cash inflows	$ 10,603,354	$ 4,300,728	$ 3,424,682
Future production costs	(5,165,626)	(2,362,243)	(1,744,947)
Future development costs	(1,529,907)	(919,418)	(667,117)
Future income taxes	—	—	—
Discount to present value at 10% annual rate	(2,021,700)	(505,696)	(419,144)
Standardized measure of discounted future net cash flows	$ 1,886,121	$ 513,371	$ 593,474

The future cash flows are based on average first-day-of-month prices during the prior 12-month period and cost rates in existence at the time of the projections.

Changes in standardized measure of discounted future net cash flows—Changes in standardized measure of discounted future net cash flows relating to proved reserves of oil, natural gas and NGLs for each of the three years in the period ended December 31, 2017 are summarized below (in thousands):

Summary of Changes	Year Ended December 31, 2017	2016	2015
Balance, beginning of period	$ 513,371	$ 593,474	$ 1,780,578
Net changes in prices and costs	915,948	(209,286)	(1,790,803)
Revisions of previous quantity estimates	(7,033)	(235,324)	(120,836)
Extensions, discoveries and improved recovery, less related costs	236,369	239,765	279,679
Sales of oil and gas - net of production costs	(452,139)	(247,126)	(292,382)
Net change in income taxes	—	—	142,761
Changes in development costs	307,280	456,565	426,246
Accretion of discount	51,337	59,347	178,058
Purchases of reserves in place	523,514	2,319	—
Sales of reserves in place	(27,057)	(49,738)	(136,828)
Change in production rates, timing, and other	(175,469)	(96,625)	127,001
Net change	1,372,750	(80,103)	(1,187,104)
Balance, end of period	$ 1,886,121	$ 513,371	$ 593,474

CORPORATE INFORMATION

Sanchez Energy Corporation

BOARD OF DIRECTORS

Antonio R. Sanchez, Jr.
Executive Chairman of the Board

Antonio R. Sanchez, III
Chief Executive Officer
Sanchez Energy Corporation

Gilbert A. Garcia
Managing Partner
Garcia Hamilton & Associates, L. P.

M. Gregory Colvin
Director

Alan G. Jackson
Senior Commercial Producer
IBC Insurance Agency, Ltd.

Sean M. Maher
Senior Portfolio Manager
RCH Energy

T. Brian Carney
Attorney

Robert V. Nelson, III
President and Chief Executive Officer
Sprint Energy Services

SENIOR MANAGEMENT

Antonio R. Sanchez, Jr.
Executive Chairman of the Board

Antonio R. Sanchez, III
Chief Executive Officer

Howard J. Thill
Executive Vice President and
Chief Financial Officer

Patricio D. Sanchez
Executive Vice President

Christopher D. Heinson
Senior Vice President and
Chief Operating Officer

Kirsten A. Hink
Senior Vice President and
Chief Accounting Officer

Gregory B. Kopel
Senior Vice President,
General Counsel and Secretary

CORPORATE ADDRESS

Sanchez Energy Corporation
1000 Main Street, Suite 3000
Houston, Texas 77002
Telephone: (713) 783.8000
Fax: (713) 756.2784
www.sanchezenergycorp.com

TRANSFER AGENT AND REGISTRAR

Continental Stock Transfer
& Trust Company
17 Battery Place, 8th Floor
New York, New York 10004
Telephone: (212) 509.4000
Fax: (212) 509.5150

INDEPENDENT AUDITORS

KPMG LLP
Houston, Texas 77002

LEGAL COUNSEL

Akin Gump Strauss Hauer & Feld LLP
Houston, Texas 77002

ANNUAL MEETING

The company's Annual Meeting of Shareholders will be held at 9:00 A.M. CT on Thursday May 24, 2018 at:

1000 Main Street,
Tunnel Level Conference Room
Houston, Texas 77002
Telephone: (713) 783.8000

FORM 10-K

Copies of the company's Annual Report on Form 10-K may be obtained, without charge, by writing to our Secretary at our Corporate Address or on the company's website at www.sanchezenergycorp.com.

COMMON STOCK LISTING

Listed on NYSE as SN

BIOGRAPHIES

The names of our directors and executive officers, and their biographies, are contained under the heading "Directors and Executive Officers" in our proxy statement, which is included with this Annual Report to Shareholders.

NYSE: **SN**

sanchezenergycorp.com

SANCHEZ
ENERGY CORPORATION