Sanchez Energy Corp
Form 10-K
February 29, 2016
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10 K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015
OR
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number: 1 35372

Sanchez Energy Corporation

(Exact name of registrant as specified in its charter)

Delaware	45 3090102
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1000 Main Street, Suite 3000	
Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

(713) 783 8000

(Registrant's telephone number, including area code)

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

(Title of Class)	(Name of Exchange)
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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b 2 of the Exchange Act.

Large accelerated filer	Accelerated filer	Non accelerated filer (Do not check if a smaller reporting company)	Smaller Reporting company

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b 2 of the Act). Yes No

Aggregate market value of the voting and non voting common equity held by non affiliates of registrant as of June 30, 2015: $534,400,409

Number of shares of registrant's common stock outstanding as of February 26, 2016: 62,579,667.

Documents Incorporated By Reference:

Portions of the registrant's definitive proxy statement for its 2016 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, 2015, are incorporated by reference into Part III of this report for the year ended December 31, 2015.

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SANCHEZ ENERGY CORPORATION

FORM 10 K

FOR THE YEAR ENDED DECEMBER 31, 2015

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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,” “project,” “profile,” “model,” “strateg negatives or the statements that include these words or other words that convey the uncertainty of future events or outcomes, are intended to identify forward looking statements, although not all forward looking statements contain such identifying words. In particular, statements, express or implied, concerning our future operating results and returns or our ability to replace or increase reserves, increase production, or generate income or cash flows are forward looking statements. Forward looking statements are not guarantees of performance. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond our control. Although we believe that the expectations reflected in our forward looking statements are reasonable and are based on reasonable assumptions, no assurance can be given that these assumptions are accurate or that any of these expectations will be achieved (in full or at all) or will prove to have been correct. Important factors that could cause our actual results to differ materially from the expectations reflected in the forward looking statements include, among others:

- our ability to successfully execute our business and financial strategies;

- our ability to utilize the services, personnel and other assets of Sanchez Oil & Gas Corporation (“SOG”) pursuant to existing services agreements;

- our ability to replace the reserves we produce through drilling and property acquisitions;

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

- the realized benefits of the acreage acquired in our various acquisitions and other assets and liabilities assumed in connection therewith;

- the realized benefits of our joint ventures, including with respect to our joint ventures with Targa Resources Partners LP (“Targa”);

- the realized benefits of our transactions with Sanchez Production Partners LP (“SPP”), including with respect to the Palmetto escalating working interest sale and divestiture of Western Catarina midstream assets referred to herein;

- the extent to which our drilling plans are successful in economically developing our acreage in, and to produce reserves and achieve anticipated production levels from, our existing and future projects;

- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;

- the extent to which we can optimize reserve recovery and economically develop our plays utilizing horizontal and vertical drilling, advanced completion technologies and hydraulic fracturing;

- our ability to successfully execute our hedging strategy and the resulting realized prices therefrom;

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· competition in the oil and natural gas exploration and production industry for employees and other personnel, equipment, materials and services and, related thereto, the availability and cost of employees and other personnel, equipment, materials and services;

· our ability to access the credit and capital markets to obtain financing on terms we deem acceptable, if at all, and to otherwise satisfy our capital expenditure requirements;

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

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

· the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations, environmental laws and regulations relating to air emissions, waste disposal, hydraulic fracturing and access to and use of water, laws and regulations imposing conditions and restrictions on drilling and completion operations and laws and regulations with respect to derivatives and hedging activities;

· developments in oil producing and natural gas producing countries, the actions of the Organization of Petroleum Exporting Countries ("OPEC") and other factors affecting the supply of oil and natural gas;

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

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

· the use of competing energy sources and the development of alternative energy sources;

· unexpected results of litigation filed against us;

· the extent to which we incur uninsured losses and liabilities or losses and liabilities in excess of our insurance coverage; and

· the other factors described under "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.

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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 exploration, acquisition and development of unconventional oil and natural gas resources in the onshore U.S. Gulf Coast, with a current focus on the Eagle Ford Shale in South Texas and, to a lesser extent, the Tuscaloosa Marine Shale ("TMS") in Mississippi and Louisiana. We have accumulated approximately 200,000 net leasehold acres in the oil and condensate, or black oil and volatile oil, windows of the Eagle Ford Shale and approximately 62,000 net leasehold acres in what we believe to be the core of the TMS. We are currently focused on the horizontal development of significant resource potential from the Eagle Ford Shale, with plans to invest approximately 100% of our total 2016 drilling and completion capital budget in this area. We are continuously evaluating opportunities to grow both our acreage and our producing assets through acquisitions. Our successful acquisition of such assets will depend on both the opportunities and the financing alternatives available to us at the time we consider such opportunities. 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."

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

Transaction	Transaction Date	Transaction Effective Date	Core Area	Net Acreage Acquired	Net Acreage Remaining at 12/31/15	Purchase / Disposition Price (millions)
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	106,100	106,100	$ 557
Wycross Acquisition	10/4/2013	7/1/2013	Wycross, Eagle Ford	3,600	3,600	$ 230
TMS transaction	8/16/2013	8/16/2013	TMS	69,000	62,000	$ 78
	7/1/2013	7/1/2013		10,300	6,300	$ 29

Five Mile Creek Acquisition			Marquis, Eagle Ford			
Cotulla Acquisition	5/31/2013	3/1/2013	Cotulla, Eagle Ford	44,500	31,200	$ 281

On October 14, 2015, the Company completed the Western Catarina Midstream Divestiture (as defined below in Note 3, "Acquisitions and Divestitures") for an adjusted purchase price of $345.8 million in cash. In connection with the closing of the Western Catarina Midstream Divestiture, the Company entered into 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, LLC ("Catarina Midstream"). In addition, for the first five years of the Gathering Agreement, SN Catarina, LLC will be required to meet a minimum quarterly volume delivery commitment of 10,200 barrels per day of crude oil and condensate and 142,000 Mcf per day of natural gas, subject to certain adjustments.

On March 31, 2015, we completed the Palmetto Disposition (as defined below in Note 3, "Acquisitions and Divestitures") 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 working interest of the purchaser, a wholly owned subsidiary of SPP, 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.

On June 30, 2014, we completed our acquisition of 106,000 net contiguous acres in Dimmit, LaSalle and Webb Counties, Texas (the "Catarina Acquisition") in the Eagle Ford Shale with an effective date of 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. Under the lease we have a 100% working interest and 75% net revenue interest in the

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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 77,000 acres of undeveloped acreage that were included in the Catarina Acquisition are subject to a continuous drilling obligation. Such drilling obligation requires us to drill (i) 50 wells in each annual period commencing on July 1, 2014 and (ii) at least one well in any consecutive 120 day period in order to maintain rights to any future undeveloped acreage. Up to 30 wells drilled in excess of the minimum 50 wells in a given annual period can be carried over to satisfy part of the 50 well requirement in the subsequent annual period on a well for well basis. The lease also created a customary security interest in the production therefrom in order to secure royalty payments to the lessor and other lease obligations. Our current capital budget and plans include drilling at least the minimum annual well requirement necessary to maintain access to such undeveloped acreage.

On October 4, 2013, we completed our acquisition of approximately 3,600 net contiguous acres of leasehold in McMullen County, Texas (the “Wycross Acquisition”) in the Eagle Ford Shale. The properties acquired in the Wycross Acquisition are included in our Cotulla area described below.

On August 16, 2013, we completed an asset acquisition of approximately 40,000 net developed and undeveloped acres in the TMS (the “TMS Transaction”) in Southwest Mississippi and Southeast Louisiana and the formation of an area of mutual interest (“AMI”) and a 50/50 joint venture with SR Acquisition I, LLC (“SR”), a subsidiary of our affiliate Sanchez Resources, LLC (“Sanchez Resources”). As of December 31, 2015 the AMI held rights to approximately 135,000 (95,000 net) acres, of which we owned approximately 62,000 net acres.

In July 2013, we acquired approximately 10,300 net acres in Fayette, Gonzales and Lavaca Counties, Texas (the “Five Mile Creek Acquisition”). The properties acquired in the Five Mile Creek Acquisition are included in our Marquis area, and are directly to the northwest of our Prost development project.

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

Our 2016 capital budget of $200 $250 million is allocated approximately 89% to the drilling of 52 net wells and to the completing of 55 net wells with the remainder allocated to facilities, leasing, and seismic activities.

For 2016, our operating plans will largely focus on continued improvement to our manufacturing efficiency with the goal of steady improvement in our capital efficiency in order to preserve liquidity and financial flexibility. Our 2016 capital budget will be focused on the development of our approximately 200,000 net acres in the Eagle Ford Shale where we plan on investing approximately 100% of the allocated drilling and completion budget.

The following table presents summary data for our Eagle Ford and TMS project areas as of December 31, 2015 as well as our capital expenditure budget for the 2016 fiscal year:

	Net Acreage	Average Working Interest (1)	Operator	Identified Drilling Locations (2) Gross	Net	2016 Capital Expenditure Budget Net Wells Spud	Net Wells Completed	Drilling & Completion ("D&C") Capital (in millions)	% of Operating Capital	% of D&C Capita
tarina	106,051	100%	Sanchez Energy	1,486	1,486	35	36	$130 - $150	62%	70%
tulla	50,984	88%	Sanchez Energy	974	891	15	15	$40 - $50	20%	23%
lmetto	8,485	48%	Marathon	317	153	2	4	$10 - $20	7%	7%
arquis	34,173	100%	Sanchez Energy	387	387	-	-	$0	0%	0%
tal gle rd	199,693	93%		3,164	2,917	52	55	$180 - $220	89%	100%
MS	61,933	65%	Sanchez Oil and Gas	300	196	-	-	$0	0%	0%
tal	261,626	84%		3,464	3,113	52	55	$180 - $220	89%	100%
cilities, asing d ismic								$20 - $30	11%	
tal pital dget								$200 - $250	100%	

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

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(2)Using approximately 40 acre well spacing for our Cotulla and Palmetto areas, approximately 60 acre well spacing for our Marquis area, and approximately 75 acre well spacing for our Catarina area plus up to 650 additional upper Eagle Ford Catarina locations, and assuming 80% of the acreage is drillable for Cotulla, Marquis and Catarina, and 90% of the acreage is drillable for Palmetto, we believe that there could be over 3,100 potential gross (2,900 net) locations for potential future drilling in the Eagle Ford. Using approximately 250 acre well spacing for our TMS area and assuming 80% of the acreage is drillable, we believe that there are up to 300 gross (200 net) locations for potential future drilling. In total, we believe that there are over 3,400 potential gross (3,100 net) Eagle Ford and TMS locations for future drilling.

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 exploiting long life, unconventional oil, condensate, NGL and natural gas reserves from the Eagle Ford Shale and the TMS, as well as a diversification into the midstream elements of the market that adds value to our 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, 2015, approximately 49% of our proved reserves were proved undeveloped. As of December 31, 2015, we were producing from 621 wells and have identified over 2,900 net locations for potential future drilling in our Eagle Ford Shale area that will be our primary targets in the near term. In 2016, we plan to invest between $180 and $220 million on development drilling and completion in the Eagle Ford Shale to spud 52 net wells and complete approximately 55 net wells. This represents approximately 100% of our 2016 drilling and completion budget and 89% of our total 2016 capital budget.

- Enhance returns by focusing on operational and cost efficiencies. We are focused on continuous 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 drill multiple wells from a single drilling pad, utilizing centralized production and fluid handling facilities and reducing the time and cost of rig mobilization.

- Add value through owning midstream functions. The Company's Marketing & Midstream Group (the "Marketing and Midstream Group") was formed in 2014 to more effectively manage our expanding midstream business segment. Our goal is to participate in the midstream function in order to capture more of the hydrocarbon value chain. The Marketing and Midstream Group focuses on projects that serve our production and add optionality to end markets which improves our netback price. As a secondary focus, the Marketing and Midstream Group also evaluates midstream projects that are accretive to the Company and add scale and diversification to our midstream portfolio.

· Adopt and employ leading drilling and completion techniques. We are focused on enhancing our drilling and completion techniques to maximize recovery of reserves. Industry techniques 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 and more tightly spaced fracture stimulation stages. We continuously evaluate industry drilling results and monitor the results of other operators to improve our operating practices, and we expect our drilling and completion techniques will continue to evolve.

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· Leverage our relationship with our affiliates to expand unconventional oil, condensate, NGL and natural gas assets. SOG, headquartered in Houston, Texas, is a private full service oil and natural gas company engaged in the exploration and development of oil and natural gas primarily in the South Texas and onshore Gulf Coast areas on behalf of its affiliates. The Company refers to SOG, Sanchez Energy Partners I, LP, and their affiliates (but excluding the Company), collectively, as the "Sanchez Group." Various members of the Sanchez Group have drilled or participated in over 1,200 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 Eagle Ford and TMS areas and compiled an extensive technological database which 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 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 also plan to selectively target additional domestic basins that would allow us to employ our strategies on attractive acreage positions that we believe are similar to our Eagle Ford Shale acreage. Our 2013 TMS Transaction was consistent with this strategy and gave us approximately 40,000 net acres, currently 62,000 net acres, within what we believe to be the core of the TMS.

· Maintain substantial financial liquidity and flexibility. As of December 31, 2015, we had approximately $435 million of cash and cash equivalents and a $500 million unused, available borrowing base (with a $300 million aggregate elected commitment amount) under our Fifth Amendment to the Second Amended and Restated Credit Agreement (defined in Note 5, "Long Term Debt"). We believe that this strong liquidity position combined with our cash flow from operations will allow us to maintain our total production of hydrocarbons at the approximate levels we reported for 2015. We plan to continuously evaluate our level of operating activity in light of both actual commodity prices and changes we are able to make to our costs of operations and make further adjustments to our capital spending program as appropriate. In addition, we expect to continue to regularly review acquisition opportunities from third parties or other members of the Sanchez Group. The Company does not expect that any potential future changes to our borrowing base would impact our aggregate elected commitment amount. Furthermore, 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 leading North American unconventional oil resource trends. We have assembled a current leasehold position of approximately 200,000 net acres in the Eagle Ford Shale, which we believe to be one of the highest rates of return unconventional oil and natural gas formations in North America. In addition to further leveraging our base of technical expertise in our project areas, 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. In addition to our Eagle Ford Shale acreage, we have approximately 62,000 net acres in what we believe to be the core of the TMS. Well results in the TMS remain strong although development is currently challenged due to high well costs and depressed commodity prices. We believe that the TMS play has significant development potential and still has significant upside as changes in technology, commodity prices, and service prices occur.

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· Proven low cost operator. We are recognized as one of the lowest cost operators in the Eagle Ford. 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 complete transparency for our well program across our organization thereby eliminating drag and waste on repetitive tasks. We have segmented and optimized each step in drilling and completing a well. Our supply chain management team takes a rigorous and methodical approach to reducing the total delivered costs of purchased good and services by examining costs on its most granular level. Goods and services are commonly sourced directly from suppliers, eliminating the middleman and markups. Additionally, we constantly review the value chain for opportunities to internally provide services in order to further reduce cost and eliminate inflation

· Demonstrated ability to drive oil production and reserves growth. Our average production for the fourth quarter of 2015 was 58,115 boe/d, substantially all of which was from the Eagle Ford Shale. This compares to approximately 52,844 boe/d in the third quarter of 2015 and 43,893 boe/d during the fourth quarter of 2014. Our total proved reserves at December 31, 2015 was 127.6 mboe, a decrease of approximately 5% over the same period a year ago, primarily due to the negative impact of SEC WTI and Henry Hub price decreases offset by an increase in drilling and development.

· Large oil weighted multi year drilling inventory. We have an inventory of over 2,900 net locations for potential future drilling on our acreage position in the oil and condensate, or black oil and volatile oil, windows of the Eagle Ford Shale based on spacing varying from 75 acres to 40 acres. In 2016, we plan to spud approximately 52 net wells and complete approximately 55 net wells on our existing Eagle Ford Shale acreage. We have an inventory of up to approximately 200 net oil weighted locations in our TMS area. Our knowledge about the basin's potential will be enhanced by continued delineation and development drilling in the TMS by us and other operators.

· 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 basins 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 staff. This technical team is large enough to support our growth into a significantly larger company relative to our current size. 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 exploitation 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 we have assembled approximately 200,000 net leasehold acres with an average working interest of approximately 93%. Using approximately 40 acre well spacing for our Cotulla and Palmetto areas, approximately 60 acre well spacing for our Marquis area, and approximately 75 acre well spacing for our Catarina area plus up to 650 additional upper Eagle Ford Catarina locations, and assuming 80% of the acreage is drillable for Cotulla, Marquis and Catarina, and 90% of the acreage is drillable for Palmetto, we believe that there could be over 3,100 potential gross (2,900 net) locations for potential future drilling. Consistent with other operators in this area, we perform multi stage hydraulic fracturing up to 30 stages on each well depending upon the length of the lateral section. For the year 2016, we plan to invest substantially all of our capital budget in the Eagle Ford Shale.

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In our Catarina area, we have approximately 106,000 net acres in Dimmit, LaSalle and Webb Counties, Texas with a 100% working interest. We anticipate drilling, completion and facilities costs on our acreage to be between $3.3 million and $3.6 million per well based on our current estimates and historical well costs. Current Estimated Ultimate Recovery (“EUR”) per well in Catarina is expected to range between 400 mboe and 1,200 mboe. We have identified between 1,300 and 1,650 gross and net locations for potential future drilling on our Catarina acreage. For the year 2016, we plan to spend $130 $150 million to spud 35 and complete 36 net wells in our Catarina area.

In our Marquis area, we have approximately 59,500 net acres, the majority of which are in southwest Fayette and northeast Lavaca Counties, Texas with a 100% working interest. We believe that our Marquis acreage lies in the volatile oil window, where we anticipate drilling, completion and facilities costs on our acreage to be between $4.0 million and $5.0 million per well based on our current estimates and historical well costs. Current EUR per well in Marquis is expected to range between 275 mboe and 375 mboe. We have identified up to 387 gross and net locations based on 60 acre well spacing for potential future drilling on our Marquis acreage. For the year 2016, we do not have any capital budgeted to spend on drilling and completions in our Marquis area.

In our Cotulla area, we have approximately 35,000 net acres in Dimmit, Frio, LaSalle, Zavala, and McMullen Counties, Texas with an average working interest of approximately 85%. We believe that our Cotulla acreage lies in the black oil window, where we anticipate drilling, completion and facilities costs on our acreage to be between $3.0 million and $4.0 million per well based on our current estimates and historical well costs. Current EUR per well in Cotulla is expected to range between 300 mboe and 400 mboe. We have identified up to 995 gross (910 net) locations based on 40 acre well spacing for potential future drilling on our Cotulla area. For the year 2016, we plan to spend $40 $50 million to spud three net wells and complete 15 net wells in our Cotulla area.

In our Palmetto area, we have approximately 8,500 net acres in Gonzales County, Texas with an average working interest of approximately 48%. We believe that our Palmetto acreage lies in the volatile oil window where we anticipate drilling, completion and facilities costs on our acreage to be between $5.5 and $6.0 million per well based on our current estimates and historical well costs. Current EUR per well in Palmetto is expected to range between 500 mboe and 600 mboe. We have identified up to 317 gross (153 net) locations based on 40 acre well spacing for potential future drilling in our Palmetto area. For the year 2016, we plan to spend $10 $20 million to spud two net wells and complete four net wells in our Palmetto area.

Tuscaloosa Marine Shale

In August 2013, we acquired approximately 40,000 net undeveloped acres in what we believe to be the core of the TMS for cash and shares of our common stock. In connection with the TMS Transaction, we established an AMI in the TMS with SR, which transaction included a carry on drilling costs for up to 6 gross (3 net) wells. As part of the transaction, we acquired all of the working interests in the AMI owned at closing from three sellers (two third parties and one related party of the Company, SR), resulting in our owning an undivided 50% working interest across the AMI through the TMS formation. As of December 31, 2015, the AMI held rights to approximately 135,000 (95,000 net) acres, of which we owned approximately 62,000 net acres.

Total consideration for the transactions consisted of approximately $70 million in cash and the issuance of 342,760 common shares of the Company, valued at approximately $7.5 million. The total cash consideration provided to SR, an affiliate of the Company, was $14.4 million, before consideration of any well carries. The acquisitions were accounted for as the purchase of assets at cost at the acquisition date. We also committed, as a part of the total consideration, to carry SR for its 50% working interest in an initial 3 gross (1.5 net) TMS wells to be drilled within the AMI (the "Initial Well Carry") with an option to drill an additional 6 gross (3 net) TMS wells ("Additional Wells") within the AMI. In August 2015, after completing the Initial Well Carry, the Company signed an agreement with SR whereby the Company paid SR approximately $8 million in lieu of drilling the remaining two Additional Wells (the "Buyout Agreement"). The Buyout Agreement stipulates that SN has earned full rights to all acreage stated in the TMS Transaction and effectively terminates any future well carry commitments.

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

Oil and Natural Gas Reserves and Production

Internal Controls

Our estimated reserves at December 31, 2015 were prepared by Ryder Scott Company, L.P. ("Ryder Scott"), our independent reserve engineers. We expect to continue to have our reserve estimates prepared semi annually by our independent third party reserve engineers. 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 secure 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 the rules of the Securities and Exchange Commission (the "SEC"), 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. Vinodh Kumar is the technical person primarily responsible for overseeing the preparation of our reserve estimates. Mr. Kumar has over 40 years of industry experience with positions of increasing responsibility in engineering and evaluations with companies such as Hilcorp Energy Company, El Paso Exploration & Production Company, KCS Energy, Inc. and Koch Industries, Inc. He holds a Masters of Science degree in Petroleum Engineering from the University of Calgary and a Masters of Business Administration from Wichita State University. Mr. Kumar 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, Sanchez Energy Partners I, LP ("SEP I")

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or us that would affect its objectivity. The engineering information presented in Ryder Scott's report was overseen by Don P. Griffin, P.E. Mr. Griffin is an experienced reservoir engineer having been a practicing petroleum engineer since 1976. He has more than 30 years of experience in reserves evaluation with Ryder Scott. He has a Bachelor of Science degree in Electrical Engineering from Texas Tech University. Mr. Griffin 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, 2015, 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.

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	As of December 31, 2015				
	Oil (mmbo)	Natural Gas Liquids (mmbbl)	Natural Gas (bcf)	Total Estimated Proved Reserves (mmboe)(2)	PV-10 (in millions)
Reserve Data (1):					
Estimated proved reserves by project area:					
Eagle Ford					
Catarina	17.3	32.4	210.0	84.8	$ 294.7
Cotulla	17.8	1.4	8.2	20.5	199.7
Marquis	3.4	0.5	2.0	4.2	51.4
Palmetto	13.1	2.5	14.2	18.0	44.0
Total Eagle Ford	51.6	36.8	234.4	127.5	589.8
TMS	0.2	—	—	0.2	3.7
Total	51.8	36.8	234.4	127.7	$ 593.5
Standardized Measure (in millions) (1)(3)					$ 593.5
Estimated proved developed reserves by project area:					
Eagle Ford					
Catarina	11.0	19.1	123.9	50.8	$ 275.5
Cotulla	6.6	1.0	5.8	8.5	115.2
Marquis	3.1	0.5	2.0	3.9	51.8
Palmetto	0.8	0.2	1.3	1.2	19.4
Total Eagle Ford	21.5	20.8	133.0	64.4	461.9
TMS	0.2	—	—	0.2	3.6
Total	21.7	20.8	133.0	64.6	$ 465.5
Estimated proved undeveloped reserves by project area:					
Eagle Ford					
Catarina	6.3	13.3	86.1	33.9	$ 19.2
Cotulla	11.2	0.4	2.4	12.0	84.5
Marquis	0.3	—	0.1	0.3	(0.4)
Palmetto	12.3	2.3	13.0	16.7	24.7
Total Eagle Ford	30.1	16.0	101.6	62.9	128.0
TMS	—	—	—	—	—
Total	30.1	16.0	101.6	62.9	$ 128.0

(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 $50.28/bo for oil, $19.90/bbl for NGLs and $2.58/mmbtu for natural gas at December 31, 2015. 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, 2015, the average realized prices for oil, NGLs and natural gas were $42.98 per bo, $11.99 per bbl and $2.63 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—Costs and Operating 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.”

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(2) One boe is equal to six mcf of natural gas or one bo of oil or NGLs based on a rough energy equivalency. This is a physical correlation and does not reflect a value or price relationship between the commodities.

(3) 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."

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, 2015 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 credit facility.

At a pace of approximately 30 wells per rig per year, our current PUD drilling locations will all be developed within the next five years by running an average gross rig count of two rigs. As of December 31, 2015, we are running two active rigs and have an approved annual budget that allows for approximately two rigs to be run through 2016. 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."

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As of December 31, 2015, we identified 218 gross (159 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, 2014 to December 31, 2015:

	Net Oil (mbbl)	Net Natural Gas Liquids (mbbl)	Net Natural Gas (mmcf)	Net Volume (mboe)
PUDs as of December 31, 2014	37,074	16,730	99,110	70,322
Revisions of previous estimates				
Revisions due to price change	(11,937)	(3,538)	(19,968)	(18,802)
Technical revisions	1,431	3,397	23,302	8,712
Extensions and discoveries	8,796	5,440	35,226	20,107
Purchases	—	—	—	—
Divestitures	—	—	—	—
Conversion to proved developed reserves during the year	(5,316)	(6,034)	(36,106)	(17,368)
PUDs as of December 31, 2015	30,048	15,995	101,564	62,971

We note that our proved reserve volumes contained in our reserve report include PUD locations that have a negative present value when discounted at 10%. There are a total of 93 such locations representing total net volumes of 29.3 mmboe in our reserve report as of December 31, 2015. Despite the negative present value associated with these locations, management considers these locations economical on an undiscounted basis, and as such, is committed to developing these locations within the next five years. Excluding acquisitions, we expect to make capital expenditures related to drilling and completion of wells of approximately $220 to $230 million during the year ending December 31, 2016. We plan to spend approximately 50% to 52% of these capital expenditures on development of PUDs in 2016. Technical revisions of PUD estimates are a result of changes in forecasted performance. There are net positive changes on our PUD forecasts driven by better performance on our Catarina asset. As a result of price change, approximately 89 PUD locations were removed. The total PUD volumes impacted by price changes are 18,802 mboe as a result of the locations that were removed from our Catarina, Marquis, and Wycross assets.

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.”

Reconciliation of PV 10 to Standardized Measure

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.

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The following table provides a reconciliation of PV 10 to the Standardized Measure at December 31, 2015 for our proved reserves (in millions):

	Proved Reserves
PV-10	$ 593.5
Present value of future income taxes discounted at 10%	—
Standardized Measure (1)	$ 593.5

(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.”

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Production, Revenues and Price History

The following table sets forth information regarding combined net production 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,		
	2015	2014	2013
Production:			
Oil - mbo			
Catarina	3,209.9	846.7	—
Marquis	1,447.8	1,910.4	724.5
Cotulla	1,832.4	1,868.1	1,098.3
Palmetto	606.0	1,422.6	1,085.6
Other	68.6	31.8	0.2
Total	7,164.7	6,079.6	2,908.6
Natural gas liquids - mbbl			
Catarina	5,065.6	1,579.5	—
Marquis	217.6	251.2	63.8
Cotulla	332.2	485.7	204.5
Palmetto	138.7	273.7	186.7
Other	—	—	—
Total	5,754.1	2,590.1	455.0
Natural gas - mmcf			
Catarina	33,775.4	9,244.2	—
Marquis	901.4	974.4	383.7
Cotulla	2,117.2	3,066.6	1,402.1
Palmetto	773.5	1,542.3	1,234.4
Other	26.6	—	28.3
Total	37,594.1	14,827.5	3,048.5
Net production volumes:			
Total oil equivalent (mboe)	19,184.4	11,141.0	3,871.6
Average daily production (boe/d)	52,560.1	30,523.2	10,607.1
Average Sales Price (1):			
Oil ($ per bo)	$ 42.98	$ 88.64	$ 99.82
Natural gas liquids ($ per bbl)	$ 11.99	$ 25.86	$ 28.60
Natural gas ($ per mcf)	$ 2.63	$ 4.06	$ 3.64
Oil equivalent ($ per boe)	$ 24.80	$ 59.79	$ 81.21
Average unit costs per boe:			
Oil and natural gas production expenses	$ 8.16	$ 8.40	$ 9.21
Production and ad valorem taxes	$ 1.40	$ 3.39	$ 4.47
General and administrative (2)(3)	$ 2.89	$ 4.40	$ 6.73
Depreciation, depletion, amortization and accretion	$ 17.96	$ 30.35	$ 34.82
Impairment of oil and natural gas properties	$ 71.15	$ 19.19	$ —

(1)Excludes the impact of derivative instruments.

(2)For the years ended December 31, 2015, 2014 and 2013, general and administrative excludes non-cash stock-based compensation expense of approximately $14.8 million ($0.77 per boe), $12.8 million ($1.15 per boe), and $17.8 million ($4.58 per boe), respectively.

(3)For the years ended December 31, 2015, 2014 and 2013, general and administrative excludes acquisition and divestiture costs included in general and administrative expense of $3.8 million ($0.20 per boe), $1.8 million ($0.16 per boe), and $4.1 million ($1.07 per boe), respectively.

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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, 2015, 15 gross wells were in various stages of completion.

	Year Ended December 31,					
	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	128.0	108.0	115.0	82.0	84.0	59.5
Dry	—	—	—	—	—	—
Exploratory wells:						
Productive	8.0	8.0	6.0	5.5	4.0	3.1
Dry	—	—	—	—	—	—
Total wells:						
Productive	136.0	116.0	121.0	87.5	88.0	62.6
Dry	—	—	—	—	—	—

The following table sets forth information at December 31, 2015 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	
	Gross	Net	Gross	Net
Operated by us	210.0	172.0	295.0	292.7
Non-operated	115.0	39.6	1.0	0.3
Total	325.0	211.6	296.0	293.0

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2015 relating to our leasehold acreage. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary. As of December 31, 2015, 71% of our acreage was held by production.

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Catarina	22,125	22,125	83,926	83,926
Cotulla	5,840	5,144	52,040	45,840
Marquis	4,140	4,140	30,033	30,033
Palmetto	3,160	1,525	14,424	6,960
Total Eagle Ford	35,265	32,934	180,423	166,759
TMS	1,000	652	94,057	61,281
Total	36,265	33,586	274,480	228,040

As of December 31, 2015, approximately 71% of our acreage was held by production. We have leases that were not held by production representing 15,383 net acres (11,137 of which were in the Eagle Ford Shale) expiring in 2016, 15,522 net acres (12,249 of which were in the Eagle Ford Shale) expiring in 2017, and 44,355 net acres (9,192 of which

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were in the Eagle Ford Shale) expiring in 2018 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 2016 and beyond. In addition to these lease expirations, we also 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.

Delivery Commitments

We have made commitments to certain purchasers to deliver a portion of our natural gas production from our Cotulla and Catarina areas.

The total amount contracted to be delivered in our Cotulla area is approximately 18 bcf of natural gas through 2021. The price for these deliveries is set at the time of delivery of the product. We have more production capacity than the amounts committed and none of the commitments in any given year are material.

In our Catarina area, we have contracts with three processing facilities to deliver a portion of our natural gas production. The total amount contracted to be delivered in our Catarina area is approximately 356 bcf of natural gas with contracts expiring in 2016, 2020 and 2021. During 2015, we recorded expenses related to deficiencies on delivery commitments. These amounts were recorded to oil and natural gas production expenses 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 do not expect to have additional expenses in 2016 related to deficiencies on our delivery commitments.

Also in our Catarina area, we have one contract to deliver a portion of our oil production. The total amount contracted to be delivered in our Catarina area is approximately 19 MMBbls of oil expiring in 2020. We do not expect to have additional expenses in 2016 related to deficiencies on our 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 20.9% to 30.5%, resulting in a net revenue interest to us ranging from 69.5% to 79.1%.

Marketing and Major Customers

For the year ended December 31, 2015, purchases by two of our customers accounted for 38% and 14%, respectively, of our total revenues. The two customers purchased oil, NGLs and natural gas production 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, NGLs and natural gas 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 oil, NGLs and natural gas 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—Costs and Operating 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."

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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, 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 and completion equipment. 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.

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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 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 clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus 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

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anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to strict and joint and several liability 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." 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. 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

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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 April 7, 2015, the EPA published a proposed rule establishing federal pre-treatment standards for wastewater discharged from onshore unconventional oil and gas extraction facilities to publicly owned treatment works (“POTWs”). The EPA asserts that wastewater from such facilities can be generated in large quantities and can contain constituents that may disrupt POTW operations and/or be discharged, untreated, from the POTW to receiving waters. If adopted, the new pre-treatment rule would require unconventional oil and gas facilities to pre-treat wastewater before transferring it to POTWs. The public comment period ended on July 17, 2015, and the EPA is expected to publish a final rule by August 2016. 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.

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. Spill prevention, control and countermeasure, or SPCC, plan requirements imposed under the Clean Water Act require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. 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, as well as prepare Facility Response Plans for responding to a worst case discharge of oil into waters of the United States. Under the OPA, strict and joint and several liability may be imposed on "responsible parties" 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 and natural resource damages, resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility. These laws and any implementing regulations may impose substantial potential liability for the costs of removal, remediation and damages. 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 SPCC plans, in connection with on-site storage of significant quantities of oil. We maintain all required discharge permits necessary to conduct our operations, and we believe we are in substantial compliance with their terms.

It is customary to recover oil and natural gas from deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate oil and natural gas production. 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

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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.

The federal Safe Drinking Water Act, or 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. 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.

On May 9, 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking public comment on its intent to develop and issue regulations under the Toxic Substances Control Act regarding the disclosure of information related to the chemicals used in hydraulic fracturing. The public comment period ended on September 18, 2014. The EPA plans to develop a Notice of Proposed Rulemaking by December 2016, which would describe a proposed mechanism – regulatory, voluntary, or a combination of both – to collect data on hydraulic fracturing chemical substances and mixtures.

In addition, 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. The rule took effect on June 24, 2015, although it is the subject of several pending lawsuits filed by industry groups and at least four states, alleging that federal law does not give the BLM authority to regulate hydraulic fracturing. On September 30, 2015, the United States District Court for Wyoming issued a preliminary injunction preventing BLM from implementing the rule nationwide. This order has been appealed to the Tenth Circuit Court of Appeals.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities. In June 2015, the EPA released its draft assessment report for peer review and public comment, finding that, while there are certain mechanisms by which hydraulic fracturing activities could potentially impact drinking water resources, there is no evidence available showing that those mechanisms have led to widespread, systemic impacts. 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 hydraulic fracturing in certain circumstances 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 hydraulic fracturing well operators disclose the list of chemical ingredients subject to the requirements of the federal Occupational Safety and Health Act, as amended, or OSHA, to state regulators and the public. 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.

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. If hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to 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 legislative 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 federal or state legislation governing hydraulic fracturing is enacted into law.

Air Emissions

The federal Clean Air Act, as amended, or the CAA, 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 rule includes NSPS for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rule seeks 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. For example, in September 2013 and December 2014, the EPA amended its rules to extend compliance deadlines and to clarify the NSPS. Further, on July 31, 2015, the EPA finalized two updates to the NSPS to address the definition of low-pressure wells and references to tanks that are connected to one another (referred to as connected in parallel). In addition, on September 18, 2015, the EPA published a suite of proposed rules to reduce methane and VOC emissions from oil and gas industry, including new “downstream” requirements covering equipment in the natural gas transmission segment of the industry that was not regulated by the 2012 rules. The public comment period closed on December 4, 2015.

Also, on January 22, 2016, the BLM announced a proposed rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The proposed rule would require 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 would also clarify when operators owe the government royalties for flared gas.

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

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane, and other greenhouse gases, or GHGs, present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. In response to its endangerment finding, the EPA recently adopted two sets of rules regarding possible future regulation of GHG emissions under the CAA. The motor vehicle rule, which became effective in July 2010, purports to limit emissions of GHGs from motor vehicles. The EPA adopted the stationary source rule (the "Tailoring Rule") in May 2010, and it became effective in January 2011. The Tailoring Rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the PSD and Title V programs of the CAA. On June 23, 2014, in Utility Air Regulatory Group v. EPA ("UARG v. EPA"), the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On December 19, 2014, the EPA issued two memorandums providing initial guidance on GHG permitting requirements in response to the Court's decision in UARG v. EPA. In its preliminary guidance, the EPA indicates it will undertake a rulemaking action to rescind any PSD permits issued under the portions of the Tailoring Rule that were vacated by the Court. In the interim, the EPA issued a narrowly crafted "no action assurance" indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to GHGs in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit. On April 30, 2015, the EPA issued a final rule allowing permitting authorities to rescind PSD permits issued under the invalid regulations.

In September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA published a final rule expanding the GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. In October 2015, the EPA amended the GHG reporting rule to add the reporting of GHG emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines.

In addition, the EPA has continued to adopt GHG regulations of other industries, such as its August 2015 adoption of three separate, but related, actions to address carbon dioxide pollution from power plants, including final Carbon Pollution Standards for new, modified and reconstructed power plants, a final Clean Power Plan to cut carbon dioxide pollution from existing power plants, and a proposed federal plan to implement the Clean Power Plan emission guidelines. Upon publication of the Clean Power Plan on October 23, 2015, more than two dozen States as well as industry and labor groups challenged the Clean Power Plan in the D.C. Circuit Court of Appeals.

In addition, the U.S. Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Furthermore, some states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources. Although the U.S. Congress has not adopted comprehensive GHG legislation at this time, it may do so in the future, and many states continue to pursue regulations to reduce GHG emissions.

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Furthermore, in December 2015, the United States joined the international community at 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, if ratified, establishes a framework for the parties to cooperate and report actions to reduce GHG emissions.

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, 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 may seek to enforce environmental laws and regulations against us and could allege personal injury or property damages. While our business is not a party to this 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 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 DOI, 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. For those current activities, however, as well as for future or proposed exploration and development plans, on federal lands, governmental permits or authorizations that are subject to the requirements of NEPA are required. This process has the potential to delay 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

Additionally, environmental laws such as the Endangered Species Act, as amended, or the ESA, may impact exploration, development and production activities on public or private lands. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the U.S., and prohibits taking of endangered species. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Federal agencies are required to insure 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.

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Occupational Safety and Health Act

We are also subject to the requirements of 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.

Legislation continues to be introduced in The U.S. Congress, and the development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including oil and natural gas facilities. Our operations may be subject to such laws and regulations. Presently, we do not believe that compliance with these laws will have a material adverse impact on us.

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.

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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, or 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 allowables 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 with SOG (the “Services Agreement”), SOG performs services for us, including the operation of our properties. Please also read Note 9, “Related Party Transactions.” As of December 31, 2015, SOG had approximately 200 employees, including 25 engineers, 11 geoscientists and 16 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 Laredo and 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, actually occurs, our business, business prospects, financial condition, results of operations or cash flows could be materially adversely affected. The risks below are not the only ones facing our 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.

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Risks Related to Our Business

Drilling wells is speculative, often involving significant costs that may be more than our estimates, and may not result in any discoveries or additions to our future production or reserves. Any material inaccuracies in estimated reserves, estimated drilling costs or underlying assumptions will materially affect our business.

Exploring for and developing oil and natural gas reserves involves a high degree of operational and financial risk, which precludes definitive statements as to the time required and costs involved in reaching certain objectives. The budgeted costs of drilling, completing and operating wells are often exceeded and can increase significantly when drilling costs rise due to a tightening in the supply of various types of oilfield equipment and related services. Drilling may be unsuccessful for many reasons, including geological conditions, weather, cost overruns, equipment shortages and mechanical difficulties. Exploratory wells bear a much greater risk of loss than development wells. Moreover, the successful drilling of an oil or natural gas well does not ensure a profit on investment. A variety of factors, both geological and market related, can cause a well to become uneconomic or only marginally economic. Our initial drilling locations, and any potential additional locations that may be developed, require significant additional exploration and development, regulatory approval and commitments of resources prior to commercial development. If our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our business operations as proposed and would be forced to modify our plan of operation.

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

· the level of oil, natural gas and NGL prices;

· 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, 2015 had decreased by 10%, then the standardized measure of our estimated proved reserves as of that date would have decreased by approximately $200.7 million, from approximately $593.5 million to approximately $392.8 million.

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Our standardized measure is calculated using unhedged oil, natural gas and NGL prices 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.

Prospects that we decide to drill may not yield oil, natural gas or NGLs in commercially viable quantities.

Our prospects are in various stages of evaluation. There is no way to predict with certainty in advance of drilling and testing whether any particular prospect will yield oil, natural gas or NGLs in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies, and the study of producing fields in the same area, will not enable us to know conclusively before drilling whether oil, natural gas or NGLs will be present or, if present, whether oil, natural gas or NGLs will be present in commercially viable quantities. Moreover, the analogies we draw from available data from other wells, more fully explored prospects or producing fields may not be applicable to our drilling prospects.

Our estimated oil, natural gas and NGL reserves 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 oil, natural gas and NGL reserves, 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 oil, natural gas and NGL reserves 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. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce as much oil, natural gas and NGLs as we had estimated. 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 greater pre drilling expenditures than traditional drilling strategies. 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 oil, natural gas and NGL prices;

· 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;

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- 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 natural gas leaks, oil, natural gas and NGL spills, salt water 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, NGL 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.

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Our acquisition, development and production operations require us to make substantial capital expenditures. Although we expect to fund our capital expenditure budget for 2016 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 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 NGL reserves. 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 proved oil, natural gas and NGL reserves;
- 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 NGL assets, 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.

Continued decreases in our revenues or the borrowing base under our revolving credit facility as a result of lower oil, NGL or natural gas prices, operating difficulties, declines in reserves or for any other reason, will adversely impact our ability to obtain the capital necessary to sustain our operations at current levels. 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.

Market conditions for oil, natural gas and NGLs, and particularly the recent declines in prices for these commodities, have, and are expected to continue to 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;

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- overall domestic and global economic conditions;
- political and economic conditions in oil, natural gas and NGL producing countries globally, 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 oil, natural gas and NGL prices;
- 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;
- the proximity, capacity, cost and availability of oil, natural gas and NGL pipelines and other transportation facilities;
- the availability of refining capacity; and
- the price and availability of alternative fuels.

In the past, oil, natural gas and NGL prices have been extremely volatile, and we expect this volatility to continue. Beginning in the latter part of 2014, oil prices declined precipitously, and continued to decline throughout 2015 as well as the start of 2016. The West Texas Intermediate posted price used to calculate the full cost ceiling in accordance with SEC rules declined from a high of $105.34 per bo on July 1, 2014 to $69.00 per bo on December 1, 2014, and $41.85 per bo on December 31, 2015. Such 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. We recorded a full cost ceiling test impairment before income taxes of $213.8 million for the year ended December 31, 2014, and we recorded a full cost ceiling impairment test impairment after income taxes of $1,365 million for the year ended December 31, 2015. The impact of lower commodity prices adversely affecting proved reserve values primarily contributed to the ceiling impairment. Changes in production rates, prices, levels of reserves, future development costs, transfers of unevaluated properties, and other factors will determine our actual ceiling test calculation and impairment analyses in future periods. Given the current trend in commodity prices, the Company expects a continued decline in the 12 month average commodity prices, and therefore, additional impairments could be recorded during 2016.

In addition, our revenue, profitability and cash flow depend upon the prices of and demand for oil, natural gas and NGL reserves, and a sustained drop in prices has significantly and is expected to continue to 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 oil, natural gas and NGL prices 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

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· 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 our oil, natural gas and NGL production sometimes 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 26, 2016, we have commodity derivative contracts in place covering approximately 70% of the mid point of our estimated oil and natural gas production for 2016. The contracts consist of swaps and put spreads covering crude oil and natural gas production. 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, which is not under any obligation to enter into commodity derivative contracts covering any specific portion of our production.

The prices at which we enter into commodity derivative contracts covering our production in the future will be dependent upon oil, natural gas and NGL prices at the time we enter into these transactions, which may be substantially higher or lower than past or current oil, natural gas and NGL prices. Accordingly, our price hedging strategy may not protect us from significant declines in oil, natural gas and NGL prices realized for our 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 oil, natural gas and NGL prices that could have a significant adverse effect on our liquidity, business, financial condition and results of operations.

Economic uncertainty could negatively impact the prices for oil, natural gas and NGLs, limit access to the credit and equity markets, increase the cost of capital, and may have other negative consequences that we cannot predict.

If our cash flow from operations is less than anticipated and our access to capital is restricted because of economic uncertainty, we may be required to reduce our operating and capital budget, which could have a material adverse effect on our results and future operations. Ongoing uncertainty may also reduce the values we are able to realize in asset sales or other transactions we may engage in to raise capital, thus making these transactions more difficult and less economic to consummate. Additionally, demand for oil, natural gas and NGLs may deteriorate and result in lower prices for oil, natural gas and NGLs, which could have a negative impact on our revenues. Lower prices could also adversely affect the collectability of our trade receivables and cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations.

Lower oil, natural gas and NGL prices have caused us to record ceiling limitation impairments, reducing our earnings and our stockholders' equity and further declines in commodity prices may cause us to record further impairments, which would reduce our earnings and stockholders' equity.

We use the full cost method of accounting and accordingly, we capitalize all costs associated with the acquisition, exploration and development of oil, natural gas and NGL properties, including unproved and unevaluated property costs. Under full cost accounting rules, the net capitalized cost of oil, natural gas and NGL properties may not exceed a "ceiling limit" that is based upon the present value of estimated future net revenues from net proved reserves, discounted at 10%, plus the lower of the cost or fair market value of unproved properties and other adjustments as required by SEC rules. If net capitalized costs of oil, natural gas and NGL properties exceed the ceiling limit, we must charge the amount of the excess to earnings, which could have a material adverse effect on our results of operations for

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the periods in which such charges are taken. This is called a “ceiling limitation impairment.” The risk that we will experience a ceiling limitation impairment increases when oil, natural gas or NGL prices are depressed as in the current environment, if we have substantial downward revisions in estimated net proved reserves or if estimates of future development costs increase significantly. Based upon current price trends we could experience ceiling limitation impairments in future periods.

Given the decline in commodity prices throughout 2015, in each of the first three quarters of 2015, the net book value of our oil and natural gas properties exceeded our ceiling amount using the WTI unweighted 12 month average price adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price realized at the wellhead, resulting in a total write down of our oil and natural gas properties of $1,365 million after income taxes. As ceiling test computations depend upon the calculated unweighted arithmetic average prices, it is difficult to predict the likelihood, timing and magnitude of any future impairments. However, given the current trend in commodity prices, the Company expects a continued decline in 12 month average commodity prices, and, therefore, additional impairments could be recorded during 2016. A ceiling test write down would negatively affect our results of operations.

Costs associated with unevaluated properties are not initially subject to the ceiling test limitation. Rather, we assess all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value based upon our intentions, as approved by our board of directors and management, with respect to drilling on such properties, the remaining lease term, geological and geophysical evaluations, drilling results, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. These factors are significantly influenced by our expectations regarding future commodity prices, development costs, and access to capital at acceptable cost. During any period in which these factors indicate impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization and the ceiling test limitation. Accordingly, a significant change in these factors, many of which are beyond our control, may shift a significant amount of cost from unevaluated properties into the full cost pool that is subject to amortization and the ceiling test limitation.

Lower oil and natural gas prices also reduces the amount of oil and natural gas that we can produce economically. Substantial and sustained decreases in oil and natural gas prices would render uneconomic a significant portion of our development and exploitation projects. This may result in our having to make downward adjustments to our estimated proved reserves. 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, the Company's strategy is to enter into derivative arrangements covering a portion of its oil, NGL and natural gas 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

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- 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.

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

Our stock price has been volatile. For example, during the year ended December 31, 2014, our stock price had a high closing price of $38.13 per share and for the year ended December 31, 2015 our stock price had a low closing price of $3.64 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, NGLs and natural gas;
- 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;
- analysts’ reports or recommendations;
- the failure of securities analysts to cover our common stock or changes in financial estimates by analysts;
- the inability to meet the financial estimates of 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, oil, natural gas and NGL prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. Because of these uncertainties, we 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, 2015, approximately 71% of our acreage was held by production. We have leases that were not held by production representing 15,383 net acres (11,137 of which were in the Eagle Ford Shale) expiring in 2016, 15,522 net acres (12,249 of which were in the Eagle Ford Shale) expiring in 2017, and 44,355 net acres (9,192 of which were in the Eagle Ford Shale) expiring in 2018 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 2016, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business, financial condition and results of operation.

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As a result of commodity prices, we have deferred development plans in the TMS to beyond 2016. As a result of the deferment of development in this area, we expect to have approximately 4,200 acres expire in 2016 in the TMS. There are currently no proved undeveloped reserves booked in the TMS. Changes to technology, prices, or commodity prices may cause us to alter our decision to defer development beyond 2016. In addition, we continue to believe that there is significant long term upside associated with the play and plan to review leasing and renewal opportunities throughout the year that may reduce the amount of acreage lost in the play. See “Business and Properties—Properties—Developed and Undeveloped Acreage” for additional information.

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, oil, NGL and natural gas prices, 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, NGL or natural gas 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, marketing oil, NGLs and natural gas, 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 low oil, NGL and natural gas prices 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.

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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 (the "Catarina Lease"), represent approximately 66% of our proved reserves as of December 31, 2015, approximately 53% of our Eagle Ford acreage as of December 31, 2015 and, approximately 72% of our total production volumes for the year ended December 31, 2015. 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.

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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.

Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and natural gas. 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. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The Clean Water Act and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. Many state discharge regulations, and the Federal National Pollutant Discharge Elimination System general permits issued by the EPA, prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into coastal waters. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. In addition, some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Also, 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 proposed requirements related to the underground injection and disposal of fluids. See “Environmental Matters and Regulation – Water and Other Water Discharges and Spills.”

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 April 7, 2015, the EPA published a proposed rule establishing federal pre-treatment standards for wastewater discharged from onshore unconventional oil and gas extraction facilities to POTWs. The EPA asserts that wastewater from such facilities can be generated in large quantities and can contain constituents that may disrupt POTW operations and/or be discharged, untreated, from the POTW to receiving waters. If adopted, the new pre-treatment rule would require unconventional oil and gas facilities to pre-treat wastewater before transferring it to POTWs. The public comment period ended on July 17, 2015, and the EPA is expected to publish a final rule by August 2016. 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.

Compliance with environmental regulations and permit requirements governing the 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 Note 9, “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.

Our use of 2D and 3D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2D and 3D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable geoscientists to know whether hydrocarbons are, in fact, present in those structures or the amount of hydrocarbons. We employ 3D seismic technology with respect to certain of our projects. The implementation and practical use of 3D seismic technology is relatively new, unproven and unconventional, which can lessen its effectiveness, at least in the near term, and increase our costs. In addition, the use of 3D seismic and other advanced technologies requires greater pre drilling expenditures than traditional drilling strategies, and we could incur greater drilling and exploration expenses as a result of such expenditures, which may result in a reduction in our returns. As a result, our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline.

We often gather 3D seismic data over large areas. Our interpretation of seismic data delineates those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data, and in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, we will have made substantial expenditures to acquire and analyze 3D data without having an opportunity to attempt to benefit from those expenditures.

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;

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- 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.

Our completed acquisitions involve risks associated with acquisitions and integrating acquired assets, including the potential exposure to significant liabilities, and the intended benefits of these acquisitions may not be realized.

We have grown our business and our reserves through multiple significant acquisitions. Each of these acquisitions involves certain risks. The risks that we face associated with our acquisitions and integrating the assets acquired from these acquisitions into existing operations include:

- our senior management's attention being diverted from the management of daily operations to the integration of the acquired assets;

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

- the acquired assets not performing as well as we anticipate; and

- unexpected costs, delays and challenges that arise in integrating such assets into our existing operations.

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

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

In order to protect our exploration and development rights in the Catarina area, we are required to meet certain drilling and other requirements under the Catarina Lease. For example, the Catarina Lease currently requires us to drill 50 wells per year (measured from July to July). If we fail to meet the minimum drilling commitment under the terms of the Catarina Lease, we would 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). 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 would 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). Our drilling plans for our undeveloped leasehold acreage are subject to change based upon various factors, including factors that are beyond our control, such as drilling results, oil, natural gas and NGL prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. Because of these uncertainties, we cannot assure you that we will be able meet our obligations under the Catarina Lease. 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.

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.

On July 28, 2015, the Company entered into a net operating loss carryforwards (“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.

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

As of December 31, 2015, we had NOLs of $765.9 million. If we were to experience an “ownership change,” as determined under Section 382 of the Internal Revenue 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 Internal Revenue 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 not be able to generate sufficient cash flows to service all of our indebtedness and may be forced to take other actions in order to satisfy our obligations under our indebtedness, which may not be successful.

Our ability to make scheduled payments on, or to refinance, our debt obligations will depend on our financial and operating performance, which is subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We cannot assure you that our business will generate sufficient cash flows from operating activities or that future sources of capital will be available to us in an amount sufficient to permit us to service our indebtedness or to fund our other liquidity needs. If we are unable to generate sufficient cash flows to satisfy our debt obligations, we may have to undertake alternative financing plans, such as refinancing or restructuring our debt, selling assets, reducing or delaying capital investments or seeking to raise additional capital. We cannot assure you that any refinancing would be possible, that any assets could be sold or, if sold, of the timing of the sales and the amount of proceeds that may be realized from those sales, or that additional financing could be obtained on acceptable terms, if at all. Our credit facility and the indenture governing the Senior Notes (as defined in Note 5, "Long Term Debt") contain restrictions on our ability to dispose of assets and our use of any of the proceeds. Our inability to generate sufficient cash flows to satisfy our debt obligations, or to refinance our indebtedness on commercially reasonable terms, would materially and adversely affect our financial condition and results of operations.

In addition, if we cannot make scheduled payments on our debt, we will be in default and, as a result:

- our debt holders could declare all outstanding principal and interest to be due and payable;

- the lenders under our revolving credit facility could terminate their commitments to lend us money and foreclose against the assets securing their borrowings; and

- we could be forced into bankruptcy or liquidation.

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 credit facility. As of December 31, 2015, we had $1.75 billion of debt outstanding, all of which was attributable to our Senior Notes, and a borrowing base of $500 million (with an aggregate elected commitment amount of $300 million) under our credit facility for secured revolver borrowings. Our increased indebtedness could adversely affect our business. In particular, it 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 credit facility, which bears interest at variable rates. Interest rate changes will not affect the market value of any debt incurred under such facility, but could affect the amount of our interest payments, 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 facility, nor are any contemplated in the future. 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.

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Restrictive covenants may adversely affect our operations.

Our credit facility and the indenture governing the Senior Notes 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 or under our credit facility 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. In addition, an event of default under our credit facility would permit the lenders under the facility to terminate all commitments to extend further credit. If we were unable to repay those amounts, the lenders under our credit facility could proceed against the collateral granted to them to secure that debt.

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

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· 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.

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

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

The present value of future net revenues from our estimated proved reserves is not necessarily the same as the current market value of our estimated proved oil, natural gas and NGL reserves.

The present value of future net revenues from our estimated proved reserves is not necessarily the same as the current market value of our estimated proved oil, natural gas and NGL reserves. We base the estimated discounted future net cash flows from our estimated proved reserves on the unweighted arithmetic average of the first day of the month prices for each month within the 12 month period prior to the end of the reporting period and costs in effect as of the date of the estimate. However, actual future net cash flows from our oil, natural gas and NGL properties also will be affected by factors such as:

· the actual prices we receive for oil, natural gas and NGLs;

· our actual operating costs in producing oil, natural gas and NGLs;

· the amount and timing of actual production;

- the amount and timing of our capital expenditures;

- the supply of and demand for oil, natural gas and NGLs; and

- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from our estimated reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows in compliance with ASC Topic 932, Extractive Activities—Oil and Natural Gas, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

We have limited experience drilling wells on our TMS acreage, which has a short operational history and is subject to more uncertainties than our drilling program in more established formations.

We and other operators have begun drilling wells in the TMS only recently. Accordingly, there is limited information on which we can determine optimum drilling and completion strategies and drilling costs (which may be higher than other trends in which we operate), or estimate production decline rates or recoverable reserves from drilling on our acreage in this trend. Our drilling plans with respect to the TMS are flexible and depend on a number of factors, including the extent to which our initial wells in the trend are commercially successful.

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 a 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 natural gas and, to a lesser extent, oil production. The federal Safe Drinking Water Act, or SDWA, regulates the underground injection of substances through the Underground Injection Control, or UIC, Program. However, hydraulic fracturing is generally exempt from regulation under the UIC Program, 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 UIC Program. On February 12, 2014, the EPA published 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, Louisiana and Mississippi, where we maintain acreage, the EPA is encouraging state programs to review and consider use of the above-mentioned guidance. 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 Congress.

On May 9, 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking public comment on its intent to develop and issue regulations under the Toxic Substances Control Act regarding the disclosure of information related to the chemicals used in hydraulic fracturing. The public comment period ended on September 18, 2014. The EPA plans to develop a Notice of Proposed Rulemaking by December 2016, which would describe a proposed mechanism – regulatory, voluntary, or a combination of both – to collect data on hydraulic fracturing chemical substances and mixtures.

Although not presently relevant to our business since we do not currently maintain acreage on federal or Indian lands, on March 26, 2015, the 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. The rule took effect on June 24, 2015, although it is the subject of several pending lawsuits filed by industry groups and at least four states, alleging that federal law does not give the BLM authority to regulate hydraulic fracturing. On September 30, 2015, the United States District Court for Wyoming issued a preliminary injunction preventing BLM from implementing the rule nationwide. This order has been appealed to the Tenth Circuit Court of Appeals.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, the EPA has commenced a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health. In June 2015, the EPA released its draft assessment report for peer review and public comment, finding that, while there are certain mechanisms by which hydraulic fracturing activities could potentially impact drinking water resources, there is no evidence available showing that those mechanisms have led to widespread, systemic impacts. 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 hydraulic fracturing in certain circumstances or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, in December 2011, the

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Commission adopted rules and regulations requiring that hydraulic fracturing well operators disclose the list of chemical ingredients subject to the requirements of Occupational Safety and Health Act, as amended, or OSHA, to state regulators and the public. 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.

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 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.

In addition, 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, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAP, programs. The rule includes NSPS for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rule seeks to achieve a 95% reduction in 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. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of these requests for reconsideration. For example, in September 2013 and December 2014, the EPA amended its rules to extend compliance deadlines and to clarify the NSPS. Further, on July 31, 2015, the EPA finalized two updates to the NSPS to address the definition of low-pressure wells and references to tanks that are connected to one another (referred to as connected in parallel). In addition, on September 18, 2015, the EPA published a suite of proposed rules to reduce methane and VOC emissions from oil and gas industry, including new “downstream” requirements covering equipment in the natural gas transmission segment of the industry that was not regulated by the 2012 rules. The public comment period closed on December 4, 2015.

Also, on January 22, 2016, the BLM announced a proposed rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The proposed rule would require 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 would also clarify when operators owe the government royalties for flared gas.

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.

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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.

On April 2, 2007, the U.S. Supreme Court ruled, in Massachusetts, et al. v. EPA, that the CAA definition of "pollutant" includes carbon dioxide and other GHGs and, therefore, the EPA has the authority to regulate carbon dioxide emissions from automobiles. Thereafter, on December 15, 2009, the EPA published its findings that GHG emissions present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. In response to its endangerment finding, the EPA recently adopted two sets of rules regarding possible future regulation of GHG emissions under the CAA. The motor vehicle rule, which became effective in July 2010, purports to limit emissions of GHGs from motor vehicles. The EPA adopted the Tailoring Rule in May 2010, and it became effective in January 2011. The Tailoring Rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the PSD and Title V programs of the CAA. On June 23, 2014, the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On December 19, 2014, the EPA issued two memorandums providing initial guidance on GHG permitting requirements in response to the Court's decision in Utility Air Regulatory Group v. EPA. In its preliminary guidance, the EPA indicates it will undertake a rulemaking action to rescind any PSD permits issued under the portions of the Tailoring Rule that were vacated by the Court. In the interim, the EPA issued a narrowly crafted "no action assurance" indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to GHGs in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit. On April 30, 2015, the EPA issued a final rule allowing permitting authorities to rescind PSD permits issued under the invalid regulations.

In September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA published a final rule expanding the GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis, with

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reporting beginning in 2012 for emissions occurring in 2011. In October 2015, the EPA amended the GHG reporting rule to add the reporting of GHG emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines.

In addition, the EPA has continued to adopt GHG regulations of other industries, such as its August 2015 adoption of three separate, but related, actions to address carbon dioxide pollution from power plants, including final Carbon Pollution Standards for new, modified and reconstructed power plants, a final Clean Power Plan to cut carbon dioxide pollution from existing power plants, and a proposed federal plan to implement the Clean Power Plan emission guidelines. Upon publication of the Clean Power Plan on October 23, 2015, more than two dozen States as well as industry and labor groups challenged the Clean Power Plan in the D.C. Circuit Court of Appeals.

In addition, the U.S. Congress has from time to time considered legislation to reduce the emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Furthermore, some states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources. Although the U.S. Congress has not adopted comprehensive GHG legislation at this time, it may do so in the future, and many states continue to pursue regulations to reduce GHG emissions.

Furthermore, in December 2015, the United States joined the international community at 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, if ratified, establishes a framework for the parties to cooperate and report actions to reduce GHG emissions.

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."

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

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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. The CFTC proposed a new version of this rule, which we refer to as the "Re-Proposed Position Limit Rule," with respect to which the comment period has closed but a final rule has not been issued.

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, we qualify for the Non-Financial End User Exception and will not be required to post margin under the Margin Rule and the quantities under the swaps in which we participate are well within applicable limits under the Re-Proposed Position Limit 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

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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, 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 the Re-Proposed Position Limit Rule is ultimately effected, such proposed 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.

We may incur more taxes and certain of our projects may become uneconomic if certain federal income tax deductions currently available with respect to oil and natural gas exploration and production are eliminated as a result of future legislation.

Legislation is proposed from time to time that contains proposals to eliminate certain key U.S. federal income tax preferences currently available to oil and natural gas exploration and production companies. These proposals include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any of the foregoing proposals will actually be enacted or how soon any such changes in law could become effective. The passage of any legislation as a result of these proposals or any other similar change in U.S. federal income tax law could eliminate and/or defer certain tax deductions that are currently available with respect to oil and natural gas exploration and production. Any such change could materially adversely affect 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. 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.

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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.

We discuss the risks and uncertainties related to our litigation in more detail below in "Item 3. Legal Proceedings" and in Note 14, "Commitments and Contingencies."

The requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended, and the requirements of the Sarbanes Oxley Act, may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost effective manner.

We are required to comply with laws, regulations and requirements, including the reporting obligations of the Exchange Act, certain corporate governance provisions of the Sarbanes Oxley Act of 2002 (the "Sarbanes Oxley Act"), related regulations of the SEC and the requirements of the NYSE with which we were not required to comply as a private company. Complying with these statutes, regulations and requirements requires a significant amount of time from our board of directors and management and has significantly increased our legal and financial compliance costs and made such compliance more time consuming and costly. As compared to a private company, among other things, we are required to:

· maintain a more comprehensive compliance function;

· design, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes Oxley Act and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;

· comply with rules promulgated by the NYSE;

· prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;

· maintain internal policies, such as those relating to disclosure controls and procedures and insider trading;

- involve and retain to a greater degree outside counsel and accountants in the above activities; and

- maintain an investor relations function.

In addition, as a public company subject to these rules and regulations, it may become more difficult and expensive for us to obtain director and officer liability insurance, and we may be required to accept greater coverage than we desire or to incur substantial costs to obtain coverage. These factors could also make it more difficult for us to attract and retain qualified executive officers and qualified members to serve on our board of directors, particularly the audit committee of the board of directors (the “Audit Committee”).

Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future and comply with the certification and reporting obligations under Sections 302 and 404 of the Sarbanes Oxley Act. Further, our remediation efforts may not enable us to remedy or avoid material weaknesses or significant deficiencies in the future. Any failure to remediate material weaknesses or significant deficiencies and to develop or maintain effective controls, or any difficulties encountered in our implementation or improvement of our internal controls over financial reporting could result in material misstatements that are not prevented or detected on a timely basis, which could potentially subject us to sanctions or investigations by the SEC, the NYSE or other regulatory authorities. Ineffective internal controls could also cause investors to lose confidence in our reported financial information.

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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. 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.

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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 will terminate five years thereafter. 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 2016 annual meeting of stockholders, which is incorporated by reference to this report. 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.

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. This could cause the market price of our common stock to drop significantly, even if our business is doing well.

As of December 31, 2015, members of the Sanchez Group owned, in the aggregate, approximately 11% of our outstanding common stock. These shares are eligible for resale in the public markets, subject to the volume, manner of sale and other limitations under Rule 144 of the Securities Act. In addition, under certain circumstances, these persons 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. 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. 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 Note 14, "Commitments and Contingencies."

Item 4. Mine Safety Disclosures

Not applicable.

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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 closing prices of our common stock for the periods indicated:

	Common Stock	
	High	Low
2015:		
First Quarter	$ 15.97	$ 7.97
Second Quarter	$ 15.64	$ 9.62
Third Quarter	$ 9.33	$ 5.30
Fourth Quarter	$ 8.08	$ 3.64

	Common Stock	
	High	Low
2014:		
First Quarter	$ 31.98	$ 23.85
Second Quarter	$ 38.13	$ 25.98
Third Quarter	$ 36.92	$ 26.26
Fourth Quarter	$ 25.20	$ 6.48

On February 26, 2016, the last sale price of our common stock, as reported on the NYSE, was $3.32 per share.

Holders. The number of shareholders of record of our common stock was approximately 38 on February 26, 2016, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or a bank.

Dividends. We pay 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 and Series B Convertible Perpetual Preferred Stock in the amounts of 4.875% and 6.50%, respectively. As of December 31, 2015, we have paid approximately $52.9 million in dividends to holders of our Series A and Series B Convertible Perpetual Preferred Stock since their respective issuances.

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. 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, 2015 regarding the Sanchez Energy Corporation Second Amended and Restated 2011 Long Term Incentive Plan (the “LTIP”). The LTIP was approved by our stockholders on May 21, 2015, which increased

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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 in 2012.

Plan Category:	(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))	
Equity Compensation Plans Approved by Stockholders	—	N/A	5,242,056	(1)
Equity Compensation Plans Not Approved by Stockholders	N/A	N/A	N/A	
Total	—	—	5,242,056	

(1)The maximum number of shares that may be delivered pursuant to the LTIP is limited to (i) 4,000,000 shares of common stock plus the number of shares of common stock available under the predecessor to the LTIP on the record date of the 2015 Annual Meeting (the "Record Date") at which the stockholders approved the LTIP as well as (ii) upon the issuance of additional shares of common stock from time to time after the Record Date, an automatic increase of 15% of such issuance of additional shares of common stock, unless our board of directors determines to increase the maximum number of shares of common stock by a lesser amount.

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, 2015.

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, the S&P 500 Index and the S&P 500 Oil & Gas Exploration and Production Index for the period indicated as prescribed by SEC rules. "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 $100 was invested on December 19, 2011 (the date on which our common stock began regular way trading on the NYSE) in each of our common stock, the S&P 500 Index and the S&P 500 Oil & Gas Exploration and Production Index.

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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, 2015. The selected financial data is derived from our audited historical financial statements.

Our historical financial statements prior to December 19, 2011 have been prepared on a carve out basis from the accounts of SEP I. The carved out financial information includes all assets, liabilities and results of operations of the unconventional oil and natural gas properties and related assets contributed to us by SEP I for the periods prior to December 19, 2011.

Our historical financial statements prior to December 19, 2011 included in this Annual Report on Form 10 K may not necessarily reflect our financial position, results of operations, and cash flows as if we had operated as a stand alone public company during those periods. The historical financial data prior to December 19, 2011 reflect historical accounts attributable to the SEP I assets (the "SEP I Assets") on a "carve out" basis, including allocated overhead from our predecessor in interest, for periods prior to our acquisition of the SEP I Assets on December 19, 2011 and do not reflect any estimate of additional overhead that we may incur as a separate company.

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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.

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands, except per share amounts)				
REVENUES:					
Oil sales	$ 307,971	$ 538,887	$ 290,322	$ 42,377	$ 13,905
Natural gas liquids sales	69,011	66,989	13,013	15	22
Natural gas sales	98,797	60,188	11,085	766	589
Total revenues	475,779	666,064	314,420	43,158	14,516
OPERATING COSTS AND EXPENSES:					
Oil and natural gas production expenses	156,528	93,581	35,669	3,401	1,628
Production and ad valorem taxes	26,870	37,787	17,334	2,124	830
Depreciation, depletion, amortization and accretion	344,572	338,097	134,845	15,922	4,252
Impairment of oil and natural gas properties	1,365,000	213,821	—	—	—
General and administrative (1)	74,160	63,692	47,951	37,239	5,368
Total operating costs and expenses	1,967,130	746,978	235,799	58,686	12,078
Operating income (loss)	(1,491,351)	(80,914)	78,621	(15,528)	2,438
Other income (expense):					
Interest and other income (expense)	(2,163)	289	135	74	10
Interest expense	(126,399)	(89,800)	(30,934)	(99)	—
Net gains (losses) on commodity derivatives	172,886	137,205	(16,938)	(742)	(480)
Total other income (expense)	44,324	47,694	(47,737)	(767)	(470)
Income (loss) before income taxes	(1,447,027)	(33,220)	30,884	(16,295)	1,968
Income tax expense (benefit)	7,600	(11,429)	3,986	—	—
Net income (loss)	(1,454,627)	(21,791)	26,898	(16,295)	1,968
Less:					
Preferred stock dividends	(16,008)	(33,590)	(18,525)	(2,112)	—
Net income allocable to participating securities(2)(3)	—	—	(364)	—	—
Net income (loss) attributable to common stockholders	$ (1,470,635)	$ (55,381)	$ 8,009	$ (18,407)	$ 1,968
Net income (loss) per common share - basic and diluted	$ (25.70)	$ (1.06)	$ 0.22	$ (0.56)	$ 0.09
Weighted average number of shares used to calculate net income (loss) attributable to common stockholders - basic and diluted (4)	57,229	52,338	36,379	33,000	22,479

(1)Includes stock based compensation expense of $14.8 million, $12.8 million, $17.8 million and $25.5 million for the years ended December 31, 2015, 2014, 2013 and 2012, respectively. Also includes acquisition and divestiture costs of $3.8 million, $1.8 million and $4.1 million for the years ended December 31, 2015, 2014 and 2013, respectively.

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

(3)For the years ended December 31, 2015, 2014 and 2012 no losses were allocated to participating restricted stock because such securities do not have a contractual obligation to share in the Company's losses. There were no outstanding shares of participating restricted stock for the year ended December 31, 2011.

(4)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 Convertible 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

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Series A Convertible Perpetual Preferred Stock and Series B Convertible Perpetual Preferred Stock from the calculation of the denominator for diluted earnings per common share as these shares were anti dilutive. 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 Convertible Perpetual Preferred Stock and Series B Convertible Perpetual Preferred Stock from the calculation of the denominator for diluted earnings per common share as these shares were anti dilutive. The year ended December 31, 2012 excludes 184,230 shares of weighted average restricted stock and 1,992,857 shares of common stock resulting from an assumed conversion of the Company's Series A Convertible Perpetual Preferred Stock from the calculation of the denominator for diluted earnings per common share as these shares were anti dilutive. The Company had no outstanding stock awards prior to its initial grants in January 2012.

	As of December 31,				
	2015	2014	2013	2012	2011
	(in thousands)				
Balance Sheet Data:					
Working capital (1)	$ 499,112	$ 412,798	$ 54,061	$ 15,671	$ 63,890
Total assets (1)	$ 1,542,343	$ 3,042,168	$ 1,622,271	$ 426,574	$ 217,356
Long term debt, net of premium and discount	$ 1,746,966	$ 1,746,263	$ 593,258	$ —	$ —
Total stockholders' equity (deficit) / parent net investment	$ (456,169)	$ 999,587	$ 857,309	$ 366,743	$ 215,141

(1) As a result of the early adoption of ASU 2015-17 on a retrospective basis as of the quarter ended December 31, 2015, the current deferred tax liability as of December 31, 2014 was reduced by approximately $33.2 million, and the current deferred tax asset as of December 31, 2013 was reduced by approximately $6.8 million. These retrospective changes are reflected in the working capital and total assets amounts in the table above. See further discussion on the early adoption of ASU 2015-17 in Note 8, "Income Taxes."

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands)				
Cash Flow Data:					
Net cash provided by operating activities	$ 272,024	$ 415,335	$ 189,261	$ 29,072	$ 5,546
Net cash used in investing activities	$ (294,331)	$ (1,361,264)	$ (1,093,363)	$ (181,427)	$ (108,005)
Net cash provided by (used in) financing activities	$ (16,359)	$ 1,266,112	$ 1,007,286	$ 139,661	$ 165,500

Non GAAP Financial Measures

Adjusted EBITDA

We define Adjusted EBITDA as net income (loss):

· Plus:

· Interest expense, including net losses (gains) on interest rate derivative contracts;

· Net losses (gains) on commodity derivative contracts;

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

· Depreciation, depletion, and amortization and accretion;

· Stock based compensation expense;

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· Acquisition and divestiture costs included in general and administrative;

· Income tax expense (benefit);

· Loss (gain) on sale of oil and natural gas properties;

· Impairment of oil and natural gas properties; and

· Other non recurring items that we deem appropriate.

· Less:

· Premiums on commodity derivative contracts;

· Amortization of deferred gain on Western Catarina Midstream Divestiture;

· Interest income; and

· Other non recurring items that we deem appropriate.

Adjusted EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements, such as investors, commercial banks and others, to assess:

· our operating performance as compared to that of other companies and companies in our industry, without regard to financing methods, capital structure or historical cost basis; and

· our ability to incur and service debt and fund capital expenditures.

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

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

	Year Ended December 31,				
	2015	2014	2013	2012	2011
Net income (loss)	$ (1,454,627)	$ (21,791)	$ 26,898	$ (16,295)	$ 1,968
Plus:					
Interest expense	126,399	89,800	30,934	99	—
Net losses (gains) on commodity derivative contracts	(172,886)	(137,205)	16,938	742	480
Net settlements received (paid) on commodity derivative contracts	142,468	5,600	(5,787)	2,749	—
Depreciation, depletion, amortization and accretion	344,572	338,097	134,845	15,922	4,252
Impairment of oil and natural gas properties	1,365,000	213,821	—	—	—
Stock-based compensation expense	14,831	12,843	17,751	25,542	—
Acquisition and divestiture costs included in general and administrative	3,814	1,808	4,129	—	—
Write off of joint venture receivable, non-recurring	2,251	—	—	—	—
Income tax expense (benefit)	7,600	(11,429)	3,986	—	—
Less:					
Amortization of deferred gain on Western Catarina Midstream Divestiture	(3,086)	—	—	—	—
Premiums on commodity derivative contracts(1)	—	(718)	(2,838)	(3,059)	—
Interest income	(443)	(193)	(190)	(74)	(1)
Adjusted EBITDA	$ 375,893	$ 490,633	$ 226,666	$ 25,626	$ 6,699

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

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

	Year Ended December 31,				
	2015	2014	2013	2012	2011
Net cash provided by operating activities	$ 272,025	$ 415,335	$ 189,261	$ 29,072	$ 5,546
Net change in operating assets and liabilities	(27,961)	(6,238)	12,334	(3,806)	1,154
Cash reimbursements received for operating leasehold improvements	(2,648)	—	—	—	—
Interest expense, net (1)	117,723	79,850	23,584	(74)	(1)
Settlements on commodity derivative contracts, non-cash	11,466	(122)	(2,642)	434	—
Income tax expense	158	—	—	—	—
Write off of joint venture receivable, non-cash	2,251	—	—	—	—
Acquisition and divestiture costs included in general and administrative	3,814	1,808	4,129	—	—
Loss on investment in SPP	(935)	—	—	—	—
Adjusted EBITDA	$ 375,893	$ 490,633	$ 226,666	$ 25,626	$ 6,699

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

Adjusted Net Income (Loss)

We present adjusted net income (loss) attributable to common stockholders (“Adjusted Net Income (Loss)”), in addition to our reported net income (loss) in accordance with U.S. GAAP. This information is provided because management believes exclusion of the impact of the items included in our definition of Adjusted Net Income (Loss) below will help investors compare results between periods, identify operating trends that could otherwise be masked by these items and highlight the impact that commodity price volatility has on our results. We define Adjusted Net Income (Loss) as net income (loss):

Plus:

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

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Less:

- Premiums on commodity derivative contracts;
- Amortization of deferred gain on Western Catarina Midstream Divestiture;
- Preferred stock dividends; and
- Other non recurring items that we deem appropriate.

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

	Year Ended December 31,				
	2015	2014	2013	2012	2011
Net income (loss)	$ (1,454,627)	$ (21,791)	$ 26,898	$ (16,295)	$ 1,968
Less: Preferred stock dividends	(16,008)	(33,590)	(18,525)	(2,112)	—
Net income (loss) attributable to common shares and participating securities					