Sanchez Energy Corp
Form 10-K
March 12, 2014

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

ý **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2013

OR

o **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.)
1111 Bagby Street, Suite 1800 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

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 ý No o

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 o No ý

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 ý No o

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 ý No o

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. o

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2013: $657,235,464

Number of shares of registrant's common stock outstanding as of March 10, 2014: 52,038,569.

Documents Incorporated By Reference:

Portions of the registrant's definitive proxy statement for its 2014 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2013, are incorporated by reference into Part III of this report for the year ended December 31, 2013.

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We are an "emerging growth company" as defined under the Jumpstart Our Business Startups Act of 2012, commonly referred to as the "JOBS Act". We will remain an "emerging growth company" for up to five years from the date of the completion of our initial public offering, or the IPO, on December 19, 2011, or until the earlier of (1) the last day of the fiscal year in which our total annual gross revenues exceed $1 billion, (2) the date that we become a "large accelerated filer" as defined in Rule 12b-2 under the Securities Exchange Act of 1934, as amended, or the Exchange Act, which would occur if the market value of our common equity that is held by non-affiliates is $700 million or more as of the last business day of our most recently completed second fiscal quarter or (3) the date on which we have issued more than $1 billion in non-convertible debt during the preceding three year period.

As an "emerging growth company", we may take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not "emerging growth companies" including, but not limited to:

- not being required to comply with the auditor attestation requirements related to our internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act;
- reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements; and
- exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and shareholder approval of any golden parachute payments not previously approved.

In addition, Section 107 of the JOBS Act provides that an "emerging growth company" can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, or the Securities Act, for complying with new or revised accounting standards. Under this provision, an "emerging growth company" can delay the adoption of certain accounting standards until those standards would otherwise apply to private companies. We have elected to avail ourselves of this exemption from new or revised accounting standards and, therefore, we will not be subject to new or revised accounting standards at the same time as other public companies that are not emerging growth companies.

SANCHEZ ENERGY CORPORATION
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2013

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

- our ability to successfully execute our business and financial strategies;
- our ability to replace the reserves we produce through drilling and property acquisitions;
- the realized benefits of the acreage acquired in the Tuscaloosa Marine Shale (the "TMS", and such transactions, the "TMS transactions"), the acquisition of assets from Hess Corporation ("Hess", and such acquisition transaction, the "Cotulla acquisition") and liabilities assumed in connection therewith, and the acquisition of the Wycross properties described herein and other assets and liabilities assumed in connection therewith (the "Wycross acquisition");
- the extent to which our drilling plans are successful in economically developing our acreage in, and to produce reserves and achieve anticipated production levels from, our existing and future projects;
- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;
- the extent to which we can optimize reserve recovery and economically develop our plays utilizing horizontal and vertical drilling, advanced completion technologies and hydraulic fracturing;
- our ability to successfully execute our hedging strategy and the resulting realized prices therefrom;
- competition in the oil and natural gas exploration and production industry for employees and other personnel, equipment, materials and services and, related thereto, the availability and cost of employees and other personnel, equipment, materials and services;
- our ability to access the credit and capital markets to obtain financing on terms we deem acceptable, if at all, and to otherwise satisfy our capital expenditure requirements;
- the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities;

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- the timing and extent of changes in prices for, and demand for, crude oil and condensate, natural gas liquids, or NGLs, natural gas and related commodities;
- 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;
- 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, the "Company," "we," "our," "us" or similar terms), a Delaware corporation formed in August 2011, is an independent exploration and production company that is focused on the exploration, acquisition and development of unconventional oil and natural gas resources in the onshore U.S. Gulf Coast, with a current focus on the Eagle Ford Shale in South Texas and, to a lesser extent, the TMS in Mississippi and Louisiana. We have accumulated approximately 120,000 net leasehold acres in the oil and condensate, or black oil and volatile oil, windows of the Eagle Ford Shale and approximately 40,000 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 86% of our total 2014 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."

During 2013, we significantly expanded our proved reserves, production and undeveloped acreage through a series of acquisitions beginning with the Cotulla acquisition in the Eagle Ford Shale in South Texas which we closed on May 31, 2013. In this acquisition, we acquired approximately 44,461 net acres in Dimmit, Frio, LaSalle and Zavala Counties, Texas with 53 gross wells producing an estimated average of approximately 4,950 boe/d for the month of May 2013. The acquisition included estimated proved reserves as of March 31, 2013 of 14.2 mboe, 66% oil, 13% NGLs and 21% natural gas, with proved developed reserves estimated to account for approximately 48% of total proved reserves. We combined our new Cotulla assets with our previous Maverick area to form one operating area now known as our Cotulla area.

In July 2013, we acquired approximately 10,300 net acres and approximately 250 boe/d of estimated production in Fayette, Gonzales and Lavaca Counties, Texas. This acquisition, now known as our Five Mile Creek development within our Marquis Area, is directly to the northwest of our Prost development project.

On August 16, 2013, we completed an asset acquisition of approximately 40,000 net undeveloped acres in the TMS in Southwest Mississippi and Southeast Louisiana and the formation of an area of mutual interest and a 50/50 joint venture with our affiliate, SR Acquisition I, LLC (together with its parent company Sanchez Resources, LLC, where applicable, "SR"). The joint venture controls approximately 115,000 gross and 80,000 net acres in what we believe to be the core of the TMS.

On October 4, 2013, we closed our Wycross acquisition in the Eagle Ford Shale. At the effective date of July 1, 2013 this acquisition added approximately 11 MMBOE of net proved reserves, 2,000 boe/d of production and 3,600 net contiguous acres of leasehold in McMullen County, Texas.

Our 2014 capital budget of $650 - $700 million is allocated 95% to the drilling and completion of 70 net wells with the remainder allocated to facilities, leasing, and seismic activities.

For 2014, our operating plans largely focus on continued improvement to our manufacturing efficiency with the goal of steady improvement in our capital efficiency. Our 2014 capital budget will be focused on the development of our approximately 120,000 net acres in the Eagle Ford Shale. In the Eagle Ford, we plan on investing $555 - $600 million, or 90%, of our drilling and completion budget to spud and complete 68 net wells in 2014. In addition, we intend to invest $60 - $65 million on drilling and completing up to 4 gross (2 net) wells in the TMS.

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The following table presents our capital expenditure budget for the 2014 fiscal year:

	2014 Capital Budget ($MM)					
Project Area	Gross Full Year Rig Count	Net Wells Spud	Net Wells Completed	Capex	% of Operating Capital	% of Drilling and Completion ("D&C") Capital
Marquis	3.0	35	32	$300 - $315	46%	48%
Cotulla	2.0	28	28	205 - 225	32%	33%
Palmetto	0.7	5	8	50 - 60	8%	9%
TMS	1.3	2	2	60 - 65	9%	10%
Total D&C Capital Budget	7.0	70	70	$615 - $665	95%	100%
Facilities, Leasing, and Seismic				35	5%	
Total Capital Budget				$650 - $700	100%	

The following table presents summary data for our Eagle Ford project areas as of December 31, 2013:

				Identified Drilling Locations(1)		2014 Capital Expenditure Budget		
	Net Acreage	Average Working Interest	Operator	Gross	Net	Net Wells Spud	Net Wells Completed	Drilling & Completion Capex (in millions)
Marquis	68,775	100%	Sanchez	900	900	35	32	$300 - $315
Cotulla	42,117	83%	Sanchez	850	760	28	28	$205 - $225
Palmetto	9,493	48%	Marathon	395	190	5	8	$50 - $60
Total	120,385	87%		2,145	1,850	68	68	$555 - 600

(1) Using approximately 40 acre well-spacing for our Cotulla and Palmetto areas and approximately 60 acre well-spacing for our Marquis area, and assuming 80% of the acreage is drillable for Cotulla and Marquis and 90% of the acreage is drillable for Palmetto, we believe that there could be up to 2,145 gross (1,850 net) locations for potential future drilling.

Our History

We are a Delaware corporation formed in August 2011 to acquire, explore and develop unconventional oil and natural gas assets. On December 19, 2011, the Company completed its IPO of 10.0 million shares of common stock, par value $0.01 per share, at a price to the public of $22.00 per share and received net proceeds of approximately $203.3 million in cash (net of expenses and underwriting discounts and commissions).

In connection with its IPO, on December 19, 2011, the Company entered into a contribution, conveyance and assumption agreement whereby Sanchez Energy Partners I, LP ("SEP I"), an affiliate of the Company, contributed to the Company 100% of the limited liability company interests in SEP Holdings III, LLC ("SEP Holdings III"), which owns interests in unconventional oil and natural gas assets consisting of undeveloped leasehold, proved oil and natural gas reserves and related equipment and other assets (the "SEP I Assets") in exchange for approximately 22.1 million shares of the Company's common stock and $50.0 million in cash. The acquisition of oil and natural gas properties from SEP I was a transaction among entities under common control and, accordingly, the Company recorded the assets and liabilities acquired at their historical carrying values and presented the historical operations of the SEP I Assets on a retrospective basis for all periods prior to the IPO

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presented in its financial statements. In addition, the $50.0 million payment was reflected as a distribution to SEP I in the financial statements.

Also in connection with its IPO, the Company entered into a contribution agreement whereby it acquired 100% of the limited liability company interests in Marquis LLC, which owns evaluated and unevaluated properties in Fayette, Lavaca, Atascosa, Webb and DeWitt Counties of South Texas (the "Marquis Assets") in exchange for 909,091 shares of the Company's common stock, valued at $20.0 million, and approximately $89.0 million in cash from the proceeds of the IPO. The acquisition was accounted for as a purchase of assets and recorded at cost at the acquisition date.

Also in connection with its IPO, on December 19, 2011, the Company entered into a services agreement and other related agreements with Sanchez Oil & Gas Corporation ("SOG" and together with its affiliates (excluding the Company but including SEP I) collectively referred to as members of the "Sanchez Group"), an affiliate of the Company, pursuant to which SOG (directly or through its subsidiaries) agreed to provide the Company with the services and data that the Company believes are necessary to manage, operate and grow its business, and the Company agreed to reimburse SOG for all direct and indirect costs incurred on its behalf.

On June 19, 2012 and September 17, 2012, SEP I distributed substantially all of the approximately 22.1 million shares of the Company's common stock that SEP I owned to the partners of SEP I (the "Distribution"). The 21,932,659 shares of common stock distributed to SEP I's partners constituted 66.5% of the then issued and outstanding shares of the Company's common stock. The Distribution was a return on SEP I's partners' capital contributions to SEP I, thus no consideration was paid to SEP I for the shares of the Company's common stock distributed. Since June 19, 2012, the Company has not been under common control with SEP I.

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. Key elements of our business strategy include:

- ***Aggressively develop our Eagle Ford Shale leasehold positions.*** We intend to aggressively drill and develop our acreage position to maximize the value of our resource potential. At December 31, 2013, 58% of our proved reserves were proved undeveloped. As of December 31, 2013, we were producing from 188 wells and have identified over 1,800 net locations for potential future drilling in our Eagle Ford Shale area that will be our primary targets in the near term. In 2014, we plan to invest between $555 and $600 million on development drilling and completion in the Eagle Ford Shale to spud and complete approximately 68 net wells. This represents 86% of our total 2014 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.

- ***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

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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.

Leverage our relationship with our affiliates to expand unconventional oil assets. Various members of the Sanchez Group have drilled or participated in over 1,000 wells, directly and through joint ventures, and have invested substantial amounts of capital in the oil and natural gas industry since 1972. During this period, they have carefully cultivated relationships with mineral and surface rights owners in and around our 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 resources. The strength of these relationships is evidenced by the TMS transactions, where our working interest partner is another member of the Sanchez Group.

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 gives us approximately 40,000 net acres within what we believe to be the core of the TMS.

Maintain substantial financial liquidity and flexibility. As of December 31, 2013, we had approximately $154 million of cash and cash equivalents available and a borrowing capacity under our revolving credit facility of $300 million. We believe that this strong liquidity position combined with our cash flow from operations will allow us to continue executing a capital expenditure program that should result in steady growth of production, cash flow and proved reserves. 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 120,000 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 40,000 net acres in what we believe to be the core of the TMS. Recent well results by other operators in the area are encouraging with respect to both strong well performance and decreasing drilling and completion costs, which we believe will be enhanced by the significant amount of additional capital planned to be spent in the TMS during 2014 based on our announced plans and those of other operators in the basin. We plan to allocate approximately 9% of our 2014 capital budget to this area.

Demonstrated ability to drive oil production and reserves growth. Our average production for the fourth quarter of 2013 was 18,810 boe/d, substantially all of which was from the Eagle Ford Shale. This compares to approximately 11,774 boe/d in the third quarter of 2013 and 1,874 boe/d during the same period in 2012. Our total proved reserves at December 31, 2013 was 58.7 mboe, a growth of 177% over the same period a year ago.

Large oil-weighted multi-year drilling inventory. We have an inventory of over 1,800 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 60 acres to 40 acres. In 2014, we plan to spud and complete approximately 68 net wells on our existing Eagle Ford Shale acreage. We expect that our TMS acreage will also provide a multi-year inventory of additional oil-weighted locations. Both we and several other industry participants have announced plans to more aggressively test their TMS acreage in 2014 which we expect to materially increase our knowledge about the potential in this new play.

Experienced management and strong technical team. Our team is comprised of individuals with a long history in the oil and 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 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 120,000 net leasehold acres with an average working interest of approximately 87%. Using approximately 40 acre well-spacing for our Cotulla and Palmetto areas and approximately 60 acre well-spacing for our Marquis area, and assuming 80% of the acreage is drillable for Cotulla and Marquis and 90% of the acreage is drillable for Palmetto, we believe that there could be over 2,100 gross (1,800 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 2014, we plan to invest substantially all of our capital budget in the Eagle Ford Shale.

In our Marquis area, we have approximately 69,000 net operated acres, the majority of which are in southwest Fayette and northeast Lavaca Counties, Texas with a 100% working interest. We believe

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that our Marquis acreage lies in the volatile oil window where we anticipate drilling, completion and facilities costs on our acreage to be between $9.0 million and $11.0 million per well based on our historical well costs. We have drilled 24 horizontal wells in our Prost development project of our Marquis area that had average 30 day production rates of approximately 700 boe/d per well. We have identified up to 900 gross and net locations based on 60 acre well-spacing for potential future drilling on our Marquis acreage. For 2014, we plan to spend $300 - $315 million to spud 35 net wells and complete 32 net wells in our Marquis area.

In our Cotulla area, we have approximately 42,000 net acres in Dimmit, Frio, LaSalle, Zavala, and McMullen Counties, Texas with an average working interest of approximately 83%. 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 $7.0 million and $9.0 million per well based on our historical well costs. Our primary focus areas in our Cotulla area are our Alexander Ranch and Wycross development projects. In our Alexander Ranch development project, 34 wells have been brought online with average 30 day production rates of approximately 500 boe/d per well. In our Wycross development project, 15 wells have been brought online with average 30 day production rates of approximately 800 boe/d per well. We have identified up to 850 gross (760 net) locations based on 40 acre well-spacing for potential future drilling on our Cotulla area. For 2014, we plan to spend $205 - $225 million to spud and complete 28 net wells in our Cotulla area.

In our Palmetto area, we have approximately 9,500 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 $7.5 million and $11.0 million per well based on our historical well costs. We have participated in the drilling of 51 gross wells on our acreage that had an average 30 day production rate of approximately 900 boe/d per well. We have identified up to 395 gross (190 net) locations based on 40 acre well-spacing for potential future drilling in our Palmetto area. For 2014, we plan to spend $50 - $60 million to spud 5 net wells and complete 8 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 plus an initial 3 gross (1.5 net) well drilling carry. In connection with the TMS transactions, we established an AMI in the TMS with SR. 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. The AMI holds rights to approximately 115,000 gross acres and 80,000 net acres.

Total consideration for the TMS transactions consisted of approximately $70 million in cash and the issuance of 342,760 common shares of the Company, valued at approximately $7.5 million. The cash consideration provided to SR was $14.4 million. The acquisitions were accounted for as the purchase of assets at cost on the acquisition date.

We have 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. In the event that we do not fulfill in a timely manner our obligations with regard to the initial TMS well commitment we must re-assign the working interests acquired from SR. At the point that the minimum commitment is met, we will have fully paid for and earned all rights to the TMS acreage. If we desire, at our sole discretion, to continue drilling within the AMI after fulfilling the minimum well commitment, we would be required to carry SR in an additional 3 gross (1.5 net) TMS wells.

Recent well results by other operators in the area are encouraging with respect to both strong well performance and decreasing drilling and completion costs. We plan to allocate 9% of our total 2014

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capital budget to our TMS area. 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, 2013 were prepared by Ryder Scott Company, L.P., or 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 Securities and Exchange Commission, or the SEC, rules, proved reserves are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs, and under existing economic conditions, operating methods and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

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

Qualifications of Responsible Technical Persons

Internal SOG Engineers. 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, and he is a Registered Professional Engineer in the State of Texas.

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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, SEP I 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 and 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, 2013, based on a reserve report prepared by Ryder Scott, our independent reserve engineers. The standardized measure amounts shown in the table are not intended to represent the current market value of our estimated oil and natural gas reserves.

	As of December 31, 2013				
	Oil (mbo)	**Natural Gas Liquids (mbbl)**	**Natural Gas (mmcf)**	**Total Estimated Proved Reserves (mboe)(2)**	**PV-10 (in millions)**
Reserve Data(1):					
Estimated proved reserves by project area:					
Eagle Ford					
Marquis	9.2	1.1	5.2	11.2	$ 284.0
Cotulla	19.3	3.3	21.3	26.2	692.5
Palmetto	16.9	2.2	13.6	21.3	488.8
Total	45.4	6.6	40.1	58.7	$ 1,465.3
Standardized Measure (in millions)(1)(3)					$ 1,209.6
Estimated proved developed reserves by project area:					
Eagle Ford					
Marquis	4.3	0.5	2.2	5.1	$ 212.3
Cotulla	8.3	2.0	13.0	12.5	398.2
Palmetto	5.4	0.9	5.3	7.1	265.9
Total	18.0	3.4	20.5	24.7	$ 876.4
Estimated proved undeveloped reserves by project area:					
Eagle Ford					
Marquis	4.9	0.6	3.0	6.1	$ 71.7
Cotulla	11.0	1.3	8.3	13.7	294.3

Palmetto	11.5	1.3	8.3	14.2		222.9
Total	27.4	3.2	19.6	34.0	$	588.9

(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

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for the prior twelve months were $96.78/bo for oil, $41.23/bbl for NGLs and $3.67/mmbtu for natural gas at December 31, 2013. 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, 2013, the average realized prices for oil, NGLs and natural gas were $99.82 per bo, $28.60 per bbl and $3.64 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."

(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, or 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 the financial statements elsewhere in this Annual Report on Form 10-K.

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, or 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 at December 31, 2013 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, expected increases to our borrowing capacity under our credit facilities and possible issuance of debt or equity securities. For a more detailed discussion of our liquidity position, please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources."

As of December 31, 2013, we identified 184 gross (114.5 net) PUD drilling locations, 89 gross (46 net) of which were identified and economically viable at December 31, 2012 and which we

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anticipate drilling within the next five years. The table below details the activity in our PUD locations from December 31, 2012 to December 31, 2013:

	Gross Locations	Net Locations	Net Volume (mboe)
Balance, December 31, 2012	118	65.0	17,491.4
PUDs converted to PDP by drilling	(28)	(18.0)	(4,487.3)
PUDs removed due to performance	(1)	(1.0)	(43.1)
Acquisition activity	51	36.1	11,648.7
Extension & Discovery	44	32.4	9,526.2
Revisions			(120.9)
Balance, December 31, 2013	184	114.5	34,015.0

Excluding acquisitions, we expect to make capital expenditures related to drilling and completion of wells of approximately $615 to $665 million during the year ending December 31, 2014. We plan to spend approximately 75% to 80% of these capital expenditures on development of PUDs in 2014.

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 the financial statements elsewhere in this Annual Report on Form 10-K.

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 GAAP financial measure. 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, 2013 for our proved reserves (in millions).

	Reserves Proved
PV-10	$ 1,465.3
Present value of future income taxes discounted at 10%	(255.7)
Standardized Measure(1)	$ 1,209.6

(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 the financial statements elsewhere in this Annual Report on Form 10-K.

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Production, Revenues and Price History

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

	Year Ended December 31,		
	2013	**2012**	**2011**
Production:			
Oil mbo			
Marquis	724.5	67.4	
Cotulla	1,098.3	87.8	13.7
Palmetto	1,085.6	262.7	132.2
Other	0.2		
Total	2,908.6	417.9	145.9
Natural gas liquids mbbl			
Marquis	63.8		
Cotulla	204.5	0.1	
Palmetto	186.7	0.6	0.5
Other			
Total	455.0	0.7	0.5
Natural gas mmcf			
Marquis	383.7		
Cotulla	1,402.1		
Palmetto	1,234.4	226.7	104.5
Other	28.3	74.5	59.6
Total	3,048.5	301.2	164.1
Net production volumes:			
Total oil equivalent (mboe)	3,871.6	468.8	173.7
Average daily production (boe/d)	10,607.1	1,280.8	475.9
Average Sales Price:			
Oil ($ per bo)(1)	$ 99.82	$ 101.40	$ 95.31
Natural gas liquids ($ per bbl)	$ 28.60	$ 23.26	$ 47.62
Natural gas ($ per mcf)	$ 3.64	$ 2.54	$ 3.59
Oil equivalent ($ per boe)(1)	$ 81.21	$ 92.07	$ 83.57

Average unit costs per boe:

Oil and natural gas production expenses	$	9.21	$	7.26	$	9.37
Production and ad valorem taxes	$	4.47	$	4.53	$	4.78
General and administrative(2)	$	7.80	$	24.95	$	30.91
Depreciation, depletion, amortization and accretion	$	34.82	$	33.96	$	24.47

(1) Excludes the impact of oil derivative instruments.

(2) For the years ended December 31, 2013 and December 31, 2012, general and administrative excludes non-cash stock-based compensation expense of approximately $17,751 ($4.58 per boe) and $25,542 ($54.49 per boe), respectively. We did not have any stock-based compensation expense for the year ended December 31, 2011.

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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, 2013, 8 gross (3 net) wells were in various stages of completion.

	Year Ended December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	84.0	59.5	14.0	9.5	3.0	1.6
Dry						
Exploratory wells:						
Productive	4.0	3.1	6.0	5.5		
Dry						
Total wells:						
Productive	88.0	62.6	20.0	15.0	3.0	1.6
Dry						

The following table sets forth information at December 31, 2013 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	126.0	98.6		
Non-operated	61.0	26.4	1.0	0.3
Total	187.0	125.0	1.0	0.3

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2013 relating to our leasehold acreage. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary. As of December 31, 2013, 43% of our acreage was held by production.

		Developed Acreage		Undeveloped Acreage	
		Gross	Net	Gross	Net
Eagle Ford Shale	Marquis	1,560	1,560	67,215	67,215
Eagle Ford Shale	Cotulla	3,840	3,202	46,660	38,915
Eagle Ford Shale	Palmetto	2,040	977	17,785	8,516
TMS				78,764	39,382
Total		7,440	5,739	210,424	154,028

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As of December 31, 2013, we had leases representing 5,975 net acres (4,418 of which were in the Eagle Ford Shale) expiring in 2014, 38,711 net acres (38,486 of which were in the Eagle Ford Shale) expiring in 2015, and 46,871 net acres (23,355 of which were in the Eagle Ford Shale) expiring in 2016 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 2014 and beyond.

Delivery Commitments

We have made commitments to certain purchasers to deliver a portion of our gas production. The total amount contracted to be delivered is approximately 20 billion cubic feet of 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.

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 properties range from 15.5% to 28.0%, resulting in a net revenue interest to us ranging from 84.5% to 72.0%.

Marketing and Major Customers

For the year ended December 31, 2013, purchases by three of our customers accounted for 41%, 23% and 19%, respectively, of our total revenues. The three customers purchase the oil 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 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 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."

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, Chesapeake Energy Corporation, Marathon Oil Corporation, EOG Resources, Inc., Halcon Resources Corporation, and Penn Virginia Corporation. 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.

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

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otherwise relating to protection of the environment or occupational health and safety. Numerous governmental agencies, such as the Environmental Protection Agency, or the EPA, 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 activities on certain lands lying within wilderness, wetlands 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, the strict and joint and several liability nature of such laws and regulations could impose liability upon us regardless of fault.

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, 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. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not 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 environmental laws and regulations and that continued compliance with existing requirements will not materially affect us, there is no assurance that this trend 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

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the current owner or operator of the site where the release occurred, past owners or operators at the time a hazardous substance was released at the site, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons 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 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 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.

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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 conditions. The underground injection of fluids is subject to permitting and other requirements under state laws and regulation. 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 or 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 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 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

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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. A surface casing string is set deeper than the deepest usable quality fresh water zones and cemented back to the surface in accordance with the appropriate regulations, potential lease requirements and legal requirements to ensure protection of existing fresh water zones. This surface string of casing is then pressure tested to ensure mechanical integrity of the casing string prior to continuing drilling operations. Hydraulic fracturing is typically regulated by state oil and natural gas commissions. The EPA, however, recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the SDWA's Underground Injection Control, or 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 and Louisiana, where we maintain acreage, the EPA is encouraging state programs to review and consider use of the above-mentioned draft guidance.

At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by 2014, and legislation has been proposed before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process, which legislation could be reintroduced in the current session of Congress.

These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing 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, Texas recently 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. On May 16, 2013, the U.S. Department of Interior, or DOI, issued a revised proposed rule that seeks to require companies operating on federal and Indian lands to (i) publicly disclose the chemicals used in the hydraulic fracturing process; (ii) confirm their wells meet certain construction standards and (iii) establish site plans to manage flowback water. The DOI recently announced its intent to finalize the rule in 2014. In addition, on October 20, 2011, the EPA announced its intention to develop federal pre-treatment standards for wastewater discharges associated with hydraulic fracturing activities. If adopted, the new pretreatment rules will require shale gas operations to pretreat wastewater before transferring it to treatment facilities. Proposed rules are expected in April 2014.

These or any other new laws or regulations that significantly restrict hydraulic fracturing 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.

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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. In August 2012, the EPA adopted 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 standards 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. These rules may require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells by 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. The EPA intends to issue revised rules that are likely responsive to some of these requests. On September 23, 2013, EPA finalized the portion of the rule addressing VOC emissions from storage tanks, including a phase-in period and an alternative emissions limit for older tanks. 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 Clean Air Act. The motor vehicle rule, which became effective in January 2011, purports to limit emissions of GHGs from motor vehicles.. The EPA adopted the stationary source rule (or the "tailoring rule") in May 2010, and it also became effective January 2011, although on October 15, 2013, the U.S. Supreme Court announced it will review aspects of the rule in 2014.

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 addition, the EPA has continued to adopt GHG regulations of other

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industries, such as a September 2013 proposed GHG rule that, if finalized, would set New Source Performance Standards for new coal-fired and natural gas-fired power plants.

In addition, 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.

These EPA and state programs, and 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.

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

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could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Occupational Safety and Health Act

We are also subject to the requirements of 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 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

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amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

Natural Gas Regulation

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

The FERC also possesses regulatory oversight over natural gas markets, including the purchase, sale and transportation activities of non-interstate pipelines and other natural gas market participants. FERC possesses substantial enforcement authority for violations of the Natural Gas Act, 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 has 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 is currently contemplating 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. Comments on the Notice of Inquiry were submitted in February 2013. Following consideration of the comments received, FERC sent out data requests to certain marketers to obtain information related to natural gas sales transactions in July 2013.

Although natural gas prices are currently unregulated, 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 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.

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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, SOG performs services for us, including the operation of our properties. Please read Note 10 "Related Party Transactions" in the notes to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

As of December 31, 2013, SOG had approximately 150 employees, including 18 engineers, 12 geoscientists and 9 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 SOG covering approximately 60,000 square feet of office space in Houston, Texas at 1111 Bagby Street, Suite 1800, Houston, Texas 77002. Approximately 15,500 square feet of SOG's leased square footage expires in September 2014, with the remainder expiring in April 2023. SOG also 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 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.*

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, if the prices used in our reserve report as of December 31, 2013 had been $10.00 less per bo and $1.00 less per mmbtu for natural gas,

then the standardized measure of our estimated proved reserves as of that date would have decreased by approximately $179 million, from approximately $1,210 million to approximately $1,031 million.

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;

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- increases in severance taxes;
- adverse weather conditions and natural disasters;
- facility or equipment malfunctions and equipment failures or accidents, including acceleration of deterioration of our facilities and equipment due to the highly corrosive nature of sour gas;
- title problems;
- pipe or cement failures, casing collapses or other downhole failures;
- compliance with ever-changing environmental and other governmental requirements;
- environmental hazards, such as 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.

Our acquisition, development and production operations will require substantial capital expenditures, and we expect to fund these capital expenditures using cash on hand, cash generated from our operations, increased borrowings under our credit facilities and/or the issuance of debt and/or equity securities. Our failure to obtain the funds for necessary future growth capital expenditures could have a material adverse effect on our business, financial condition and results of operations.

The oil and natural gas industry is capital intensive. We expect to make substantial growth capital expenditures in our business for the acquisition, development and production of oil, natural gas and NGL reserves. We intend to finance our future growth and capital expenditures with cash on hand, cash generated from our operations, increased borrowings under our credit facilities and/or the issuance of debt and/or equity securities.

Our cash on hand, cash flows from operations, ability to borrow and access to capital are subject to a number of variables, 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;
- any interest payments, debt service and dividend payment requirements;
- prevailing economic conditions;
- our financial condition; and
- the ability and willingness of banks and other lenders to lend to us.

If we are unsuccessful in obtaining the funds we need to grow our business, we may be forced to reduce our capital expenditures and our business, financial condition and results of operations may be adversely affected.

A decline in oil, natural gas or NGL prices will cause a decline in our cash flow from operations, which could adversely affect our business, financial condition and results of operations.

The oil, natural gas and NGL markets are very volatile, and we cannot predict future oil, natural gas and NGL prices. Prices for oil, natural gas and NGLs may fluctuate widely in response to relatively minor changes in the supply of and demand for oil, natural gas and NGLs, market uncertainty and a variety of additional factors that are beyond our control, such as:

domestic and foreign supply of and demand for oil, natural gas and NGLs;

weather conditions and the occurrence of natural disasters;

overall domestic and global economic conditions;

political and economic conditions in 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 the Organization of Petroleum Exporting Countries, or 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. Such volatility may affect the amount of our net estimated proved reserves and will affect the standardized measure of discounted future net cash flows of our net estimated proved reserves.

Natural gas prices are closely linked to the supply of natural gas and consumption patterns in the United States of the electric power generation industry and certain industrial and residential users where natural gas is the principal fuel. The domestic natural gas industry continues to face concerns of oversupply due to the success of new trends and continued drilling in these trends, despite lower natural gas prices and the production of "associated gas" from liquids rich plays.

Our revenue, profitability and cash flow depend upon the prices of and demand for oil, natural gas and NGL reserves, and a drop in prices can significantly affect our financial results and impede our growth. In particular, 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; and
- limit our ability to borrow money or raise additional capital.

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 March 10, 2014, we have 23 commodity derivative contracts in place covering our expected production for 2014 and 2015. The contracts consist of swaps, collars, put spreads, and three-way costless collars, 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.

We are increasing production in areas of high industry activity, which may impact our ability to obtain the personnel, equipment, services, resources and facilities access needed to complete our development activities as planned or result in increased costs.

Our strategy is to expand drilling activity in areas in which industry activity has increased rapidly, particularly in the Eagle Ford Shale in South Texas. As a result, demand for personnel, equipment, hydraulic fracturing, water and other services and resources, as well as access to transportation, processing and refining facilities in these areas has increased, as has the costs for those items. A delay or inability to secure the personnel, equipment, services, resources and facilities access (including take away capacity) necessary for us to complete our development activities as planned could result in a rate of oil, natural gas and NGL production below the rate forecasted, and significant increases in costs would impact our profitability.

Shortages of equipment, services and qualified personnel could reduce our cash flow and adversely affect results of operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil, natural gas and NGL prices and activity levels in new regions, causing periodic shortages. During periods of high oil, natural gas and NGL prices, SOG has experienced shortages of equipment, including drilling rigs and completion equipment, as demand for rigs and equipment has increased along with higher commodity prices and increased activity levels. In addition, there is currently a shortage of hydraulic fracturing capacity in many of the areas in which we operate. Higher oil, natural gas and NGL prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, oilfield equipment and services and personnel in our exploration and production operations. These types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results and/or restrict or delay our ability to drill those wells and conduct those operations that we currently have planned and budgeted, causing us to miss our forecasts and projections.

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.

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, we will lose our right to develop the related properties on this acreage. As of December 31, 2013, we had leases representing 5,949 net acres (4,418 of which were in the Eagle Ford Shale) expiring in 2014, 38,711 net acres (38,486 of which were in the Eagle Ford Shale) expiring in 2015, and 46,871 net acres (23,355 of which were in the Eagle Ford Shale) expiring in 2016 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 2014, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business, financial condition and results of operation. See "Business and Properties Properties Developed and Undeveloped Acreage" for additional information.

Our hedging transactions could result in cash losses, limit potential gains and materially impact our liquidity.

Many of the derivative contracts to which we may be a party will require us to make cash payments to the extent the applicable index exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in oil, natural gas and NGL prices. If our actual production and sales for any period are less than our hedged production and sales for that period (including reductions in production due to operational delays) or if we are unable to perform our drilling activities as planned, 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, which may materially impact our liquidity, business, financial condition and results of operations.

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Our hedging transactions expose us to counterparty credit risk.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden changes in a counterparty's liquidity, which could impair its ability to perform under the terms of the derivative contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform under contracts with us. Even if we do accurately predict sudden changes, our ability to mitigate that risk may be limited depending upon market conditions.

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. This process is typically regulated by state agencies. The EPA, however, recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the federal SDWA 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 and Louisiana, where we maintain acreage, the EPA is encouraging state programs to review and consider use of the above-mentioned draft guidance.

At the same time, the EPA has commenced a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health, with a draft of the study anticipated to be available by 2014, and legislation has been proposed before Congress to provide for federal regulation of hydraulic fracturing and to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process, which legislation could be reintroduced in the current session of Congress. Further, certain members of the Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates.

These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing 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, Texas recently adopted rules and regulations requiring that hydraulic fracturing well operators disclose the list of chemical ingredients subject to the requirements of OSHA to state regulators and the public. On May 16, 2013, the DOI issued a revised proposed rule that seeks to require companies operating on federal and Indian lands to (i) publicly disclose the chemicals used in the hydraulic fracturing process; (ii) confirm their wells meet certain construction standards and (iii) establish site plans to manage flowback water. The DOI recently announced its intent to finalize the rule in 2014. These or any other new laws or regulations that significantly restrict hydraulic fracturing 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.

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In addition, on October 20, 2011, the EPA announced its intention to develop federal pre-treatment standards for wastewater discharges associated with hydraulic fracturing activities. If adopted, the new pretreatment rules will require shale gas operations to pretreat wastewater before transferring it to treatment facilities. Proposed rules are expected in April 2014. We cannot predict the impact that these standards may have on our business at this time, but these standards could have a material impact on our business, financial condition and results of operation.

In addition, in August 2012, the EPA adopted 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 standards 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. These rules may require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells by 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. The EPA intends to issue revised rules that are likely responsive to some of these requests. On September 23, 2013, EPA finalized the portion of the rule addressing VOC emissions from storage tanks, including a phase-in period and an alternative emissions limit for older tanks.

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 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 federal or state legislation governing hydraulic fracturing is enacted into law.

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

The present value of future net revenues from our estimated reserves is not necessarily the same as the current market value of our estimated oil, natural gas and NGL reserves. We base the estimated discounted future net cash flows from our estimated reserves on prices 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 may experience a financial loss if SOG is unable to sell a significant portion of our oil and natural gas production.

Under our Services Agreement with SOG, SOG sells a portion of our oil, natural gas and NGL production on our behalf. SOG's ability to sell our production depends upon market conditions and the demand for oil, natural gas and NGLs from SOG's customers.

In recent years, a number of energy marketing and trading companies have discontinued their marketing and trading operations, which has significantly reduced the number of potential purchasers for our production. This reduction in potential customers has reduced overall market liquidity. If any one or more of our significant customers reduces the volume of oil and natural gas production it purchases and SOG is unable to sell those volumes to other customers, then the volume of our production that SOG sells on our behalf could be reduced, which could have an adverse affect on our business, financial condition and results of operations.

In addition, a failure by any of these companies, or any purchasers of our production, to perform their payment obligations to us could have a material adverse effect on our business, financial condition and results of operations. To the extent that purchasers of our production rely on access to the debt or equity markets to fund their operations, there could be an increased risk that those purchasers could default in their contractual obligations to us. If for any reason we were to determine that it was probable that some or all of the accounts receivable from any one or more of the purchasers of our production were uncollectible, we would recognize a charge to our earnings in that period for the probable loss and could suffer a material reduction in our liquidity.

Lower oil, natural gas and NGL prices may cause us to record ceiling limitation impairments, which would reduce our 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 Regulation S-X under the Securities Act. 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 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, if we have substantial downward revisions in estimated net proved reserves or if estimates of future development costs increase significantly. No assurance can be given that we will not experience a ceiling limitation impairment in future periods.

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 through December 2014. 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.

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

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

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

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

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

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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.

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.

We may have assumed unknown liabilities in connection with our acquisitions from SEP I and Ross Exploration. We have limited or no recourse against them for losses, including for title defects.

As a result of our acquisitions of the SEP I Assets and Marquis Assets in connection with the closing of our IPO, we may have incurred significant unknown liabilities and may have limited or no contractual remedies or insurance coverage for such liabilities. Unknown liabilities could include liabilities for cleanup or remediation of undisclosed or unknown environmental conditions, claims that were not asserted or threatened prior to completion of the IPO, and tax liabilities. Further, to the extent that we have indemnification rights or a claim for damages for such liabilities, we cannot assure you that the indemnifying party will be able to fulfill its contractual obligations or otherwise satisfy any claims we may have at law or equity. Any such liability or liabilities could have a material adverse effect on our business, financial condition, results of operations and reserves.

We acquired the SEP I Assets on an "as is" basis, subject to all liabilities that existed prior to the closing of the IPO, some of which may be unknown. We have limited or no recourse against the Sanchez Group for liabilities associated with the SEP I Assets or for breaches of representations or warranties by SEP I and we cannot assure you that we have identified all areas of existing or potential exposure.

In addition and in connection with the acquisition of the Marquis Assets, we assumed certain obligations and liabilities, including unknown and contingent liabilities, arising in connection with or relating to the entity or the properties that we acquired. While we performed a certain level of due diligence in connection with the Marquis Assets and attempted to verify the representations of Ross Exploration, there may be pending, threatened, contemplated or contingent claims against the entity or the Marquis Assets related to environmental, title, regulatory, litigation or other matters of which we are unaware. In addition, we have limited or no recourse against Ross Exploration for liabilities associated with such properties. For example, Ross Exploration did not make any representations and warranties to us with respect to environmental matters that would entitle us to seek indemnification. Ross Exploration is generally not liable for any misrepresentation or breach of warranty unless we had asserted such misrepresentation or breach by December 19, 2012 and the aggregate amount of damages with respect to such misrepresentation or breach of warranty had exceeded $25,000 individually and $2.0 million in the aggregate and then only to the extent of such excess.

We did not obtain title policies or title insurance on the properties that we acquired from Ross Exploration or SEP I and may not have identified all title defects within the period that we were required to assert such defects in order to claim a reduction in the consideration paid by us.

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, primarily in the Eagle Ford Shale in South Texas and 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. As a result, we will likely be impacted more acutely by factors affecting our industry or the regions in which we operate than we would if our business were more diversified, increasing our risk profile. In particular, we may be disproportionately exposed to the impact of delays or interruptions of production from wells in which we have an interest that are caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of oil or natural gas produced from wells in the Eagle Ford Shale. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

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

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

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

Our historical financial information prior to the completion of the IPO may not be representative of the results we would have achieved as a stand-alone public company and may not be a reliable indicator of our future results.

The historical financial information prior to December 19, 2011 included in this Annual Report on Form 10-K has been prepared on a carve-out basis from the accounts of SEP I and may not necessarily reflect what our financial position, results of operations or cash flows would have been had we been an independent, stand-alone entity during the periods prior to December 19, 2011 or those that we will achieve in the future. SEP I did not account for us, and we were not operated, as a separate, stand-alone company for the historical periods presented prior to December 19, 2011. The costs and expenses reflected in our historical financial information prior to December 19, 2011 include allocations of general and administrative expenses for employee, management, and administrative support provided by SOG to SEP I. These allocations were primarily based on the ratio of capital expenditures between the entities to which SOG provides services and us, and also on other factors, such as time spent on general management services and producing property activities. Although SOG will continue to provide these services to us pursuant to our Services Agreement and management believes such allocations are reasonable, such allocations may not be indicative of the actual expense that would have been incurred had we been an independent, stand-alone entity during the periods presented. In addition, we have not adjusted our historical financial information to reflect changes that have occurred in our cost structure and operations as a result of our becoming a stand-alone public company, including potential increased costs associated with reduced economies of scale and increased costs associated with the SEC reporting and the New York Stock Exchange, or the NYSE, requirements. Therefore, our historical financial information may not necessarily be indicative of what our financial position, results of operations or cash flows will be in the future. For additional information, see "Item 6. Selected Financial Data" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," and our financial statements and related notes included elsewhere in this Annual Report on Form 10-K.

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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 Clean Air Act. The motor vehicle rule, which became effective in January 2011, purports to limit emissions of GHGs from motor vehicles.. The EPA adopted the stationary source rule (or the "tailoring rule") in May 2010, and it also became effective January 2011, although on October 15, 2013, the U.S. Supreme Court announced it will review aspects of the rule in 2014.

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 addition, the EPA has continued to adopt GHG regulations of other

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industries, such as a September 2013 proposed GHG rule that, if finalized, would set New Source Performance Standards for new coal-fired and natural gas-fired power plants.

In addition, 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.

The EPA reporting rule and 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 activities on certain lands lying within wilderness, wetlands and other protected areas; (v) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; (vi) result in the suspension or revocation of necessary permits, licenses and authorizations; (vii) impose substantial liabilities for pollution resulting from drilling and production operations; and (viii) require that additional pollution controls be installed. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly compliance or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time.

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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.

The derivatives reform legislation adopted by the U.S. Congress could have a negative impact on our ability to hedge risks associated with our business.

In 2010, Congress adopted the Dodd Frank Wall Street Reform and Consumer Protection Act (the "Dodd Frank Act"), which, among other matters, provides for federal oversight of the over the counter derivatives market and entities that participate in that market. The Dodd Frank Act mandates that the Commodity Futures Trading Commission ("CFTC"), adopt rules and regulations implementing the Dodd Frank Act and further defining certain terms used in the Dodd Frank Act. The Dodd Frank Act also requires the CFTC and the banking regulators to establish margin requirements for uncleared swaps. Although there is an exception from swap clearing and trade execution requirements for commercial end users that meet certain conditions (the "End User Exception"), certain market participants, including most if not all of our counterparties, will also be required to clear many of their swap transactions with entities that do not satisfy the End User Exception and will have to transact many of their swaps on swap execution facilities or designated contract markets, rather than over the counter on a bilateral basis. These requirements may increase the cost to our counterparties of hedging the swap positions they enter into with us, and thus may increase the cost to us of entering into our hedges. The changes in the regulation of swaps may result in certain market participants deciding to curtail or cease their derivatives activities. While many regulations have been promulgated and are already in effect, the rulemaking and implementation process is still ongoing, and the ultimate effect of the adopted rules and regulations and any future rules and regulations on our business remains uncertain.

We currently qualify as a "non-financial entity" for purposes of the End User Exception and satisfy the other requirements of the End User Exception and intend to utilize the "End-User Exception." As a result, our swaps will not be subject to mandatory clearing, we do not expect to clear our swaps and our swap transactions will not be subject to the margin requirements imposed by derivatives clearing organizations. Because the margin regulations for uncleared swaps have not been adopted, we do not yet know whether our counterparties will be required to collect liquid margin from us for those swaps.

A rule adopted under the Dodd Frank Act imposing position limits in respect of transactions involving certain commodities, including oil and natural gas was vacated and remanded to the CFTC for further proceedings by order of the United States District Court for the District of Columbia, U.S.

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District Judge Robert L. Wilkins on September 28, 2012. The CFTC appealed this decision and on November 5, 2013, filed a consensual motion to dismiss its appeal. The same day, the CFTC proposed a new position limits rule which would limit trading in New York Mercantile Exchange (NYMEX) contracts for Henry Hub Natural Gas, Light Sweet Crude Oil, New York Harbor Ultra Low Sulfur No. 2 Diesel and Reformulated Blendstock for Oxygen Blending Gasoline and other futures and swap contracts that are economically equivalent to such NYMEX contracts. Comments on the proposed rule were due on February 10, 2014. We cannot predict whether or when the proposed rule will be adopted or the effect of the proposed rule on our business. The Dodd Frank Act, the rules already promulgated thereunder and the proposed rule, if adopted, could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our potential exposure to less creditworthy counterparties. In addition, 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. If we reduce our use of derivatives or commodity prices decline as a result of the Dodd Frank Act and 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 and our results of operations. Any of these consequences could have a material and adverse effect on our business, financial condition and results of operations.

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. Indeed, on October 20, 2011, the EPA announced its intention to develop federal pre-treatment standards for wastewater discharges associated with hydraulic fracturing activities. If adopted, the new pretreatment rules will require coalbed methane and shale gas operations to pretreat wastewater before transferring it to treatment facilities. Proposed rules are expected in April 2014. Compliance with environmental regulations and permit requirements governing 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.

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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, 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:

- institute a more comprehensive compliance function;
- design, establish, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 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;
- establish new 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
- establish 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.

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 of 2002. 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.

In addition, once we cease to be an emerging growth company, we will be subject to additional laws, regulations and requirements.

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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 changes 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 changes will actually be enacted or how soon any such changes could become effective. The passage of any legislation as a result of the budget proposal 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 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 the IPO, we entered into several agreements with members of the Sanchez Group. These agreements were made in the context of a parent-subsidiary relationship. 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 amended and 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 amended and 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;

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- to the fullest extent permitted by law, members of the Sanchez Group will have no duty to communicate their knowledge of, or offer, any potential business opportunity, transaction, or other matter to us, and members of the Sanchez Group are free to pursue or acquire such business opportunity, transaction, or other matter for themselves or direct the business opportunity, transaction, or other matter to its affiliates; and

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

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

Certain services required by us for the operation of our business, including general and administrative services, geological, geophysical and reserve engineering, lease and land administration, marketing, accounting, operational services, information technology services, compliance, insurance maintenance and management of outside professionals, are provided by SOG pursuant to our Services Agreement with SOG. 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 2014 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.

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 that we entered into with SOG at the closing of the IPO, 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 our Services Agreement see Note 10 "Related Party Transactions" in the notes to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" of this Annual Report on Form 10-K. This database includes the 2D and 3D seismic data used for our exploration and development projects as well as the well logs, LAS files, scanned well documents and other well documents and software that are necessary for our daily operations. This information is critical for the operation and expansion of our business. Under certain circumstances, including if SOG provides at least 180 days' advance written notice of its desire to terminate the Services Agreement, the license agreement will terminate and we will lose our rights to this technological database unless members of the Sanchez Group permit us to retain some or all of these rights, which they may decline to do in their sole discretion. In such event, we are unlikely to be able to obtain rights to similar information under substantially similar commercial terms or to continue our business operations as proposed and our liquidity, business, financial condition and results of operations will be materially and adversely affected and it could delay or prevent an acquisition of us.

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.

Our stock price may be volatile, and investors in our common stock could incur substantial losses.

Our stock price may be volatile. The stock market in general has experienced extreme volatility that has often been unrelated to the operating performance of particular companies. 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 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.

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.

Members of the Sanchez Group own, in the aggregate, approximately 13% 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. In addition, under certain circumstances, members of the Sanchez Group 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.

We are subject to anti-takeover provisions in our amended and restated certificate of incorporation and amended and restated bylaws and under 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 amended and 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 Delaware General Corporation Law, which prohibits, with some exceptions, stockholders owning in excess of 15% of our outstanding voting stock from merging or combining with us. Finally, our amended and restated bylaws establish advance notice requirements for nominations for election to our board of directors and for proposing matters that can be acted upon at stockholder meetings. Although we believe these provisions together provide an opportunity to receive higher bids by requiring potential acquirers to negotiate with our board of directors, they would apply even if an offer to acquire us may be considered beneficial by some stockholders.

We 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.

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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 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, 2013, we had $600 million of debt outstanding, all of which was attributable to our Senior Notes, and a borrowing base of $300 million under our credit facility, all of which was available for future 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 facilities, 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.

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;

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- 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 indenture 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 to which a cross-acceleration or cross-default provision applies. 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 you, including the following:

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

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

We have no experience drilling wells on our TMS acreage, which has a limited operational history and is subject to more uncertainties than our drilling program in more established formations.

Operators have begun drilling wells in the TMS only recently. Accordingly, we have 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

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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.

The TMS transactions and the Wycross and Cotulla acquisitions involve risks associated with acquisitions and integrating acquired assets, including the potential exposure to significant liabilities, and the intended benefits of the TMS transactions and the Wycross and Cotulla acquisitions may not be realized.

The TMS transactions and the Wycross and Cotulla acquisitions each involve risks associated with acquisitions and integrating acquired assets into existing operations, including that:

- our senior management's attention may be diverted from the management of daily operations to the integration of the assets acquired in the TMS transactions and the Wycross and Cotulla acquisitions;

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

- the assets acquired in the TMS transactions and the Wycross and Cotulla acquisitions may not perform as well as we anticipate; and

- unexpected costs, delays and challenges may arise in integrating the assets acquired in the TMS transactions and the Wycross and Cotulla acquisitions into our existing operations.

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

We are subject to legal proceedings and legal compliance risks.

We, including our officers and directors, are involved in various legal proceedings. 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*, in this Annual Report on Form 10-K and in Note 15 in the notes to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

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*

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. We are not aware of any material governmental proceedings against us or contemplated to be brought against us.

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Litigation

On December 4, 13, and 16, 2013, three derivative actions were filed in the Court of Chancery of the State of Delaware against the Company, certain of its officers and directors, Sanchez Resources, LLC, Altpoint Capital Partners LLC, and Altpoint Sanchez Holdings, LLC (the "Consolidated Derivative Actions," Friedman v. A.R. Sanchez, Jr. et al., No. 9158; City of Roseville Employees' Retirement System v. A.R. Sanchez, Jr. et al., No. 9132; and Delaware County Employees Retirement Fund v. A.R. Sanchez, Jr. et al., No. 9165).

On December 20, 2013, the Consolidated Derivative Actions were consolidated, co-lead counsel for the plaintiffs was appointed and the plaintiffs were ordered to file an amended consolidated complaint (In re Sanchez Energy Derivative Litigation, Consolidated C.A. No. 9132-VCG). On January 28, 2014, a verified consolidated stockholder derivative complaint was filed. The Consolidated Derivative Actions concern the Company's purchase of working interests in the Tuscaloosa Marine Shale from Sanchez Resources, LLC. Plaintiffs allege breaches of fiduciary duty against the individual defendants as directors of the Company; breaches of fiduciary duty against Antonio R. Sanchez, III as an executive director of the Company; aiding and abetting breaches of fiduciary duty against Sanchez Resources, LLC, Eduardo Sanchez, Altpoint Capital Partners LLC, and Altpoint Sanchez Holdings, LLC; and unjust enrichment against A.R. Sanchez, Jr. and Antonio R. Sanchez, III. The Consolidated Derivative Actions are in their preliminary stages, and the Company is unable to reasonably predict an outcome or to estimate a range of reasonably possible loss.

On January 9, 2014, a derivative action was filed in 333rd district court in Harris County, Texas against the Company and certain of its officers and directors, styled Martin v. Sanchez, No. 2014-01028 (333rd Dist. Harris County, Texas). The complaint alleges a breach of fiduciary duty, corporate waste, and unjust enrichment against various officers and directors. No action has been taken to date and damages are unspecified. This action is in its preliminary stages, and the Company is unable to reasonably predict an outcome or to estimate a range of reasonably possible loss.

On February 12, 2014, a derivative action was filed in the United States District Court for the Southern District of Texas, Houston Division, against the Company and certain of its officers and directors, styled Bartlinski v. Sanchez, No. 4:14-cv-00341 (S.D. Tex.). The complaint alleges a violation of Section 14(a) of the Exchange Act and SEC Rule 14a-9. No action has been taken to date and damages are unspecified. This action is in its preliminary stages, and the Company is unable to reasonably predict an outcome or to estimate a range of reasonably possible loss.

Defendants believe that the allegations contained in the matters described above are without merit and intend to vigorously defend themselves against the claims raised.

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
2013:		
First Quarter	$ 21.62	$ 17.10
Second Quarter	$ 23.43	$ 17.02
Third Quarter	$ 27.60	$ 20.40
Fourth Quarter	$ 30.92	$ 22.71

	Common Stock	
	High	Low
2012:		
First Quarter	$ 25.23	$ 16.96
Second Quarter	$ 25.37	$ 18.43
Third Quarter	$ 21.62	$ 16.37
Fourth Quarter	$ 20.62	$ 16.90

On March 10, 2014, the last sale price of our common stock, as reported on the NYSE, was $28.48 per share.

Holders. The number of shareholders of record of our common stock was approximately 51 on March 10, 2014, 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 on our Series A and Series B Convertible Perpetual Preferred Stock in the amounts of 4.875% and 6.50%, respectively. No dividends were accrued or accumulated prior to September 17, 2012. As of December 31, 2013, we have paid approximately $20.6 million in dividends to holders of our Series A and Series B Convertible Perpetual Preferred Stock.

We have not paid any cash dividends on our common equity since our inception. Although our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities, we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future. We currently intend to retain future earnings to finance the expansion of our business.

Securities Authorized for Issuance Under Equity Compensation Plans. The following table sets forth certain information as of December 31, 2013 regarding the Sanchez Energy Corporation Amended and

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Restated 2011 Long Term Incentive Plan, or the 2011 Plan. The 2011 Plan was approved by our stockholders at our 2012 annual meeting of stockholders.

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	4,671,461(1)
Equity Compensation Plans Not Approved by Stockholders	N/A	N/A	N/A
Total			4,671,461

(1) The maximum number of shares that may be delivered pursuant to the 2011 Plan is limited to 15% of our issued and outstanding shares of common stock. This maximum amount automatically increases to 15% of the issued and outstanding shares of common stock immediately after each issuance by us of our 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, 2013.

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Comparative Stock Performance

The performance graph below compares the cumulative total stockholder return for our common stock to that of the Standard and Poor's, or S&P, 500 Index and the S&P 500 Oil & Gas Exploration and Production Index for the period 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.

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 Acts 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.

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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, 2013. The selected financial data as of December 31, 2013, 2012, 2011, 2010 and 2009 and for the years ended December 31, 2013, 2012, 2011, 2010 and 2009 are 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 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,				
	2013	2012	2011	2010	2009
	(in thousands, except per share amounts)				
REVENUES:					
Oil sales	$ 290,322	$ 42,377	$ 13,905	$ 4,404	$ 241
Natural gas liquids sales	13,013	15	22		
Natural gas sales	11,085	766	589	149	
Total revenues	314,420	43,158	14,516	4,553	241
OPERATING COSTS AND EXPENSES:					
Oil and natural gas production expenses	35,669	3,401	1,628	391	9
Production and ad valorem taxes	17,334	2,124	830	214	11
Depreciation, depletion, amortization and accretion(1)	134,845	15,922	4,252	1,430	1,029
General and administrative(2)	47,951	37,239	5,368	5,276	1,833
Gain on sale of oil and natural gas properties					(2,686)
Total operating costs and expenses	235,799	58,686	12,078	7,311	196
Operating income (loss)	78,621	(15,528)	2,438	(2,758)	45
Other income (expense):					
Interest and other income	135	74	10		
Interest expense	(30,934)	(99)			
Net losses on derivatives	(16,938)	(742)	(480)		
Total other income (expense)	(47,737)	(767)	(470)		
Income (loss) before income taxes	30,884	(16,295)	1,968	(2,758)	45
Income tax expense	3,986				
Net income (loss)	26,898	(16,295)	1,968	(2,758)	45
Less:					
Preferred stock dividends	(18,525)	(2,112)			
Net income allocable to participating securities	(364)				
Net income (loss) attributable to common stockholders	$ 8,009	$ (18,407)	$ 1,968	$ (2,758)	$ 45
Net income (loss) per common share basic and diluted	$ 0.22	$ (0.56)	$ 0.09	$ (0.12)	$

Weighted average number of shares used to calculate net income (loss) attributable to common stockholders basic and diluted(3)(4)	36,379	33,000	22,479	22,091	22,091

(1) Includes $614,000 of full cost ceiling test impairment for the year ended December 31, 2009.

(2) Includes stock-based compensation expense of $17.8 million and $25.5 million for the years ended December 31, 2013 and 2012, respectively.

(3) 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

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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.

(4) Weighted average shares used to compute earnings (loss) per share for the years ended December 31, 2010 and 2009 includes those shares issued to SEP I by the Company in connection with and as partial consideration for the acquisition of the SEP I Assets, which shares have been retroactively reflected as outstanding for all periods presented.

	As of December 31,				
	2013	2012	2011	2010	2009
	(in thousands)				
Balance Sheet Data:					
Working capital (deficit)	$ 60,943	$ 15,671	$ 63,890	$ (1,818)	$ 59
Total assets	$ 1,629,153	$ 426,574	$ 217,356	$ 26,765	$ 13,275
Long term debt, net of discount	$ 593,258	$	$	$	$
Total parent net investment / stockholders' equity	$ 857,309	$ 366,743	$ 215,141	$ 22,162	$ 13,218

	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(in thousands)				
Cash Flow Data:					
Net cash provided by (used in) operating activities	$ 189,261	$ 29,072	$ 5,546	$ (3,777)	$ (1,710)
Net cash provided by (used in) investing activities	$ (1,093,363)	$ (181,427)	$ (108,005)	$ (7,925)	$ 2,734
Net cash provided by (used in) financing activities	$ 1,007,286	$ 139,661	$ 165,500	$ 11,702	$ (1,024)

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 derivatives;

Net settlements received (paid) on commodity derivatives;

Premiums paid on commodity derivative contracts;

Depreciation, depletion, and amortization and accretion;

Stock-based compensation expense;

Acquisition costs included in general and administrative;

Income tax expense (benefit);

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

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Impairment of oil and natural gas properties; and

Other non-recurring items that we deem appropriate.

Less:

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 or loss, operating income or loss, cash flows provided by or used in operating activities or any other measure of financial performance or liquidity presented in accordance with 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, except per share data):

	Year Ended December 31,				
	2013	**2012**	**2011**	**2010**	**2009**
Net income (loss)	$ 26,898	$ (16,295)	$ 1,968	$ (2,758)	$ 45
Plus:					
Interest expense	30,934	99			
Net losses on commodity derivatives	16,938	742	480		
Net settlements on commodity derivatives	(5,787)	2,749			
Premiums paid on commodity derivative contracts	(2,838)	(3,059)			
Depreciation, depletion, amortization and accretion	134,845	15,922	4,252	1,430	415
Impairment of oil and natural gas properties					614
Stock-based compensation	17,751	25,542			
Acquisition costs included in general and administrative	4,129				
Income tax expense	3,986				
Less:					
Interest income	(190)	(74)	(1)		
Gain on sale of oil and natural gas properties					(2,686)
Adjusted EBITDA	$ 226,666	$ 25,626	$ 6,699	$ (1,328)	$ (1,612)

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

	Year Ended December 31,				
	2013	2012	2011	2010	2009
Net cash provided by (used in) operating activities	$ 189,261	$ 29,072	$ 5,546	$ (3,777)	$ (1,710)
Net change in operating assets and liabilities	9,692	(3,372)	1,154	2,449	98
Interest (income) expense, net(1)	23,584	(74)	(1)		
Acquisition costs included in general and administrative	4,129				
Adjusted EBITDA	$ 226,666	$ 25,626	$ 6,699	$ (1,328)	$ (1,612)

(1) Excludes amortization of deferred financing costs and accretion of debt discount of $(7,160), $(99), and $0 for the years ended December 31, 2013, 2012, and 2011, respectively.

Adjusted Net Income

We present adjusted net income attributable to common stockholders, or Adjusted Net Income, in addition to our reported net income (loss) in accordance with GAAP. This information is provided because management believes exclusion of the impact of our unrealized derivatives not accounted for as cash flow hedges and stock-based compensation expense 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 as net income (loss):

Plus:

- Net losses (gains) on commodity derivatives;
- Net settlements received (paid) on commodity derivatives;
- Premiums paid on commodity derivative contracts;
- Stock-based compensation expense;
- Acquisition costs included in general and administrative;
- Other non-recurring items that we deem appropriate; and
- Tax impact of adjustments to net income (loss).

Less:

Preferred stock dividends; and

Other non-recurring items that we deem appropriate.

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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,				
	2013	2012	2011	2010	2009
Net income (loss)	$ 26,898	$ (16,295)	$ 1,968	$ (2,758)	$ 45
Less: Preferred stock dividends	(18,525)	(2,112)			
Net income (loss) attributable to common shares and participating securities	8,373	(18,407)	1,968	(2,758)	45
Plus:					
Net losses on commodity derivatives	16,938	742	480		
Net settlements paid on commodity derivatives	(5,787)	2,749			
Premiums paid on commodity derivative contracts	(2,838)	(3,059)			
Stock-based compensation	17,751	25,542			
Acquisition costs included in general and administrative	4,129				
Tax impact(3)	(3,898)				
Adjusted net income (loss)	34,668	7,567	2,448	(2,758)	45
Adjusted net income allocable to participating securities	(1,513)	(221)			
Adjusted net income (loss) attributable to common stockholders	$ 33,155	$ 7,346	$ 2,448	$ (2,758)	$ 45
Adjusted net income (loss) per common share basic and diluted(1)(2)	$ 0.91	$ 0.22	$ 0.11	$ (0.12)	$
Weighted average number of unrestricted outstanding common shares to calculate adjusted net income (loss) per common share basic and diluted	36,379	33,000	22,479	22,091	22,091

(1) 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.

(2) 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 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.

(3) The tax impact is computed by utilizing the Company's effective tax rate on the adjustments to reconcile net income to Adjusted net income.

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Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes appearing elsewhere in this Annual Report on Form 10-K.

Business Overview

Sanchez Energy Corporation is an independent exploration and production company focused on the exploration, acquisition and development of unconventional oil and natural gas resources in the onshore U.S. Gulf Coast, with a current focus on the Eagle Ford Shale in South Texas and, to a lesser extent, the TMS in Mississippi and Louisiana. We have accumulated approximately 120,000 net leasehold acres in the oil and condensate, or black oil and volatile oil, windows of the Eagle Ford Shale and approximately 40,000 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 86% of our 2014 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."

During 2013, we significantly expanded our proved reserves, production and undeveloped acreage through a series of acquisitions beginning with the Cotulla acquisition in the Eagle Ford Shale in South Texas which we closed on May 31, 2013. We acquired approximately 44,461 net acres in Dimmit, Frio, LaSalle and Zavala Counties of South Texas with 53 gross wells producing an estimated average of approximately 4,950 boe/d for the month of May 2013. The acquisition included estimated proved reserves as of March 31, 2013 of 14.2 mboe, 66% oil, 13% NGLs and 21% natural gas, with proved developed reserves estimated to account for approximately 48% of total proved reserves. We combined our new Cotulla assets with our previous Maverick area to form one operating area now known as our Cotulla area.

In July 2013, we acquired approximately 10,300 net acres and approximately 250 boe/d of estimated production in Fayette, Gonzales and Lavaca Counties, Texas for approximately $29 million. This acquisition, now known as our Five Mile Creek development within our Marquis Area, is directly to the northwest of our Prost development project.

On August 8, 2013 we announced an asset acquisition of approximately 40,000 net undeveloped acres in the TMS in Southwest Mississippi and Southeast Louisiana and the formation of an area of mutual interest and a 50/50 joint venture with our affiliate, SR. The joint venture controls approximately 115,000 gross and 80,000 net acres in what we believe to be the core of the TMS.

On October 4, 2013, we closed our Wycross acquisition in the Eagle Ford Shale. At the effective date of July 1, 2013 this acquisition added approximately 11 MMBOE of net proved reserves, 2,000 boe/d of production and 3,600 net contiguous acres of leasehold in McMullen County, Texas.

Basis of Presentation

The acquisition of oil and natural gas properties from SEP I was a transaction among entities under common control and accordingly, the Company recorded the assets and liabilities acquired at their historical carrying values and has presented the historical accounts of the SEP I Assets on a retrospective basis for all periods prior to the IPO presented in the consolidated financial statements.

SOG is a private oil and gas company engaged in the exploration for and development of oil and natural gas. SOG has historically acted as the operator of a significant portion of SEP I's oil and natural gas properties. SOG provided all employee, management, and administrative support to SEP I and, for periods prior to December 19, 2011, a proportionate share of SOG's general and administrative costs were allocated to the SEP I Assets. The costs of these services associated with the SEP I Assets were allocated to the SEP I Assets primarily based on the ratio of capital expenditures between the entities to which SOG provides services and the SEP I Assets. However, other factors, such as time spent on general management services and producing property activities, were also considered in the allocation of these costs. Management believes such allocations were reasonable; however, they may not be indicative of the actual expense that would have been incurred had the SEP I Assets been operated as an independent company for periods prior to December 19, 2011. On December 19, 2011, SOG began providing similar types of services to the Company under the services agreement as described Note 10 "Related Party Transactions" in the notes to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

Our Properties

Eagle Ford Shale

We and our predecessor entities have a long history in the Eagle Ford Shale, where we have assembled approximately 120,000 net leasehold acres with an average working interest of approximately 87%. Using approximately 40 acre well-spacing for our Cotulla and Palmetto areas and approximately 60 acre well-spacing for our Marquis area, and assuming 80% of the acreage is drillable for Cotulla and Marquis and 90% of the acreage is drillable for Palmetto, we believe that there could be up to 2,100 gross (1,800 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 2014, we plan to invest substantially all of our capital budget in the Eagle Ford Shale.

In our Marquis area, we have approximately 69,000 net operated 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 $9.0 million and $11.0 million per well based on our historical well costs and publicly available information. We have drilled 24 horizontal wells in our Prost area of Marquis that had average 30 day production rates of approximately 700 boe/d. We have identified up to 900 gross and net locations based on 60 acre well-spacing for potential future drilling on our Marquis acreage. For 2014, we plan to spend $300 - $315 million to spud 35 net wells and complete 32 net wells in our Marquis area.

In our Cotulla area, we have approximately 42,000 net acres in Dimmit, Frio, LaSalle, Zavala, and McMullen Counties, Texas with an average working interest of approximately 83%. 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 $7.0 million and $9.0 million per well based on our historical well costs and publicly available information. Our primary focus areas in our Cotulla area are our Alexander Ranch and Wycross development projects. In our Alexander Ranch development project 34 wells have been brought online with average 30 day production rates of approximately 500 boe/d. In our Wycross development project 15 wells have been brought online with average 30 day production rates of approximately 800 boe/d. We have identified up to 850 gross (760 net) locations based on 40 acre well-spacing for potential future drilling on our Cotulla area. For 2014, we plan to spend $205 - $225 million to spud and complete 28 net wells in our Cotulla area.

In our Palmetto area, we have approximately 9,500 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 $7.5 million and $11.0 million per well based on our historical well costs and publicly available information. We have participated in the drilling of 51 gross wells on our acreage that had an average 30 day production rates of approximately 900 boe/d. We have identified up to 395 gross (190 net) locations based on 40 acre well-spacing for potential future drilling in our Palmetto area. For 2014, we plan to spend $50 - $60 million to spud 5 and complete 8 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 plus an initial 3 gross (1.5 net) well drilling carry. In connection with the TMS transactions, we established an AMI in the TMS with SR. 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. The AMI holds rights to approximately 115,000 gross acres and 80,000 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. The acquisitions were accounted for as the purchase of assets at cost at the acquisition date.

We have also committed, as a part of the total consideration, to carry SR for its 50% working interest in an initial 3 gross (1.5 net) TMS wells to be drilled within the AMI. In the event that we do not fulfill in a timely manner our obligations with regard to the initial TMS well commitment we must re-assign the working interests acquired from SR. At the point that the minimum commitment is met, we will have fully paid for and earned all rights to the TMS acreage. If we desire, at our sole discretion, to continue drilling within the AMI after fulfilling the minimum well commitment, we would be required to carry SR in an additional 3 gross (1.5 net) TMS wells.

Recent well results by other operators in the area are encouraging with respect to both strong well performance and decreasing drilling and completion costs. We plan to allocate 9% of our total 2014 capital budgets to this area. The average remaining lease term on the acreage is over 3 years, giving us ample time to allow other industry participants to further de-risk the play.

Recent Developments

On January 15, 2014, we announced our 2014 capital budget of $650 - $700 million, allocated 95% to the drilling and completion of 70 net wells with the remainder allocated to facilities, leasing, and seismic activities.

Our 2014 capital budget will be focused on the development of our approximately 120,000 net acres in the Eagle Ford Shale. In the Eagle Ford, we plan on investing $555 - $600 million, or 90%, of our drilling and completion budget to spud and complete 68 net wells in 2014.

In addition, we intend to invest $60 - $65 million on drilling and completing up to 4 gross (2 net) wells in the TMS. The capital allocated to this area will fulfill our drilling carry obligation under our agreements entered into in connection with the TMS transactions.

Outlook

As an oil and natural gas company, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well or formation decreases. Our future growth will depend on our ability to continue to add new reserves in excess of our production. Accordingly, we plan to maintain our focus on adding reserves through development projects associated with our current property base, improving the economics of producing oil and

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natural gas from our properties and selected step-out and exploratory drilling activities. In addition, we regularly review acquisition opportunities from third parties or other members of the Sanchez Group. Our ability to add estimated reserves through acquisitions and development projects is dependent on many factors, including our ability to raise capital, obtain regulatory approvals and procure contract drilling rigs and personnel. Volatility in commodity prices and sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce, the price of our common stock, and our access to capital.

Results of Operations

Revenue and Production

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

	Year Ended December 31,			Increase (Decrease) 2013 vs 2012		Increase (Decrease) 2012 vs 2011	
	2013	2012	2011	$	%	$	%
Net Production:							
Oil (mbo)	2,908.6	417.9	145.9	2,490.7	596%	272.0	186%
Natural gas liquids (mbbl)	455.0	0.7	0.5	454.3	*	0.2	40%
Natural gas (mmcf)	3,048.5	301.2	164.1	2,747.3	912%	137.1	84%
Total oil equivalent (mboe)	3,871.6	468.8	173.7	3,402.8	726%	295.1	170%
Average Sales Price(1):							
Oil ($ per bo)	$ 99.82	$ 101.40	$ 95.31	$ (1.58)	(2)%	$ 6.09	6%
Natural gas liquids ($ per bbl)	$ 28.60	$ 23.26	$ 47.62	$ 5.34	23%	$ (24.36)	(51)%
Natural gas ($ per mcf)	$ 3.64	$ 2.54	$ 3.59	$ 1.10	43%	$ (1.05)	(29)%
Oil equivalent ($ per boe)	$ 81.21	$ 92.07	$ 83.57	$ (10.86)	(12)%	$ 8.50	10%
REVENUES(1):							
Oil sales	$ 290,322	$ 42,377	$ 13,905	$ 247,945	585%	$ 28,472	205%
Natural gas liquids sales	13,013	15	22	12,998	*	(7)	(32)%
Natural gas sales	11,085	766	589	10,319	*	177	30%
Total revenues	$ 314,420	$ 43,158	$ 14,516	$ 271,262	629%	$ 28,642	197%

* Not meaningful.

(1) Excludes the impact of derivative instruments.

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Net Production. Production increased from 173.7 mboe in 2011 to 3,871.6 mboe in 2013 due to our drilling program and acquisition activity. The number of gross wells producing at year end and the production for the periods were as follows:

	Year Ended December 31,					
	2013		2012		2011	
	# Wells	mboe	# Wells	mboe	# Wells	mboe
Marquis	34	852.2	3	67.4		
Cotulla	100	1,536.4	10	87.9	3	13.7
Palmetto	53	1,478.1	18	301.1	9	150.1
Other	1	4.9	1	12.4	1	9.9
Total	188	3,871.6	32	468.8	13	173.7

In 2013, 75% of our production was oil, 12% was NGLs and 13% was natural gas compared to 2012 production that was 89% oil, de minimis NGLs and 11% natural gas. In 2011, 84% of our production was oil, de minimis NGLs and 16% was natural gas..

Average Sales Price. Our average realized oil price for the year ended December 31, 2013 was $99.82 per bo, 2% lower than the average sales price in 2012 of $101.40 per bo and 5% higher than the average sales price in 2011 of $95.31 per bo. The average price realized for our NGL production in 2013 was $28.60 per bbl, 23% higher than the average sales price in 2012 of $23.26 per bbl and 40% lower than the average sales price in 2011 of $47.62 per bbl. The average price realized for our natural gas production in 2013 was $3.64 per mcf, 43% higher than the average sales price in 2012 of $2.54 per mcf and 1% higher than the average sales price in 2011 of $3.59 per mcf.

Revenues. Oil and natural gas sales revenues totaled approximately $314.4 million, $43.2 million and $14.5 million for the years ended December 31, 2013, 2012 and 2011, respectively. Oil sales revenue for the year ended December 31, 2013 increased $247.9 million as compared to the year ended December 31, 2012, with $252.5 million attributable to the increase in production partially offset by $4.6 million due to the lower average sales price compared to 2012. For the year ended December 31, 2012 compared to 2011, oil sales revenue increased $28.5 million with $25.9 million attributable to the increase in production and $2.6 million due to the higher average sales price. Natural gas sales revenue for the year ended December 31, 2013 increased $10.3 million with $7.0 million attributable to the increase in production and $3.3 million due to the higher average sales price compared to 2012. Natural gas sales revenue for the year ended December 31, 2012 increased approximately $177,000 with $492,000 attributable to the increase in production partially offset by $315,000 due to the lower average sales price compared to 2011. NGL sales revenue for the year ended December 31, 2013 increased $13.0 million based upon an increase in production compared to 2012. NGL sales revenue for the years ended December 31, 2012 and 2011 was de minimis.

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Operating Costs and Expenses

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

	Year Ended December 31,			Increase (Decrease) 2013 vs 2012		2012 vs 2011	
	2013	2012	2011	$	%	$	%
OPERATING COSTS AND EXPENSES:							
Oil and natural gas production expenses	$ 35,669	$ 3,401	$ 1,628	$ 32,268	949%	$ 1,773	109%
Production and ad valorem taxes	17,334	2,124	830	15,210	716%	1,294	156%
Depreciation, depletion, amortization and accretion	134,845	15,922	4,252	118,923	747%	11,670	274%
General and administrative (inclusive of stock-based compensation expense of $17,751 and $25,542 for the years ended December 31, 2013 and 2012, respectively)	47,951	37,239	5,368	10,712	29%	31,871	594%
Total operating costs and expenses	235,799	58,686	12,078	177,113	302%	46,608	386%
Interest and other income	135	74	10	61	82%	64	*
Interest expense	(30,934)	(99)		30,835	*	99	*
Net losses on commondity derivatives	(16,938)	(742)	(480)	16,196	*	262	(55)%
Income tax expense	(3,986)			3,986	*		*

* Not meaningful.

Oil and Natural Gas Production Expenses. Oil and natural gas production expenses are the costs incurred to produce our oil and natural gas, as well as the daily costs incurred to maintain our producing properties. Such costs also include field personnel costs, utilities, chemical additives, salt water disposal, maintenance, repairs and occasional well workover expenses related to our oil and natural gas properties. Our oil and natural gas production expenses increased by approximately $32.3 million to approximately $35.7 million for the year ended December 31, 2013, as compared to $3.4 million for the same period in 2012 and $1.6 million for the same period in 2011. The increase in oil and natural gas production expenses from 2011 to 2013 is directly attributable to the increase in production resulting from our increased production activities and well count in the Eagle Ford Shale, largely as a result of the Cotulla and Wycross acquisitions completed during 2013. Our average production expenses increased from $7.26 per boe during the year ended December 31, 2012 to $9.21 per boe for the year ended December 31, 2013. The increase in production expenses per boe during the period was due to higher per boe costs related to the properties acquired from Hess in the Cotulla acquisition. These higher costs were the result of a significant amount of equipment rentals on the acquired properties. There was a reduction in equipment rentals during the latter part of 2013 that the Company expects to continue to contribute to a decrease in production expenses per boe going forward.

Production and Ad Valorem Taxes. Production and ad valorem taxes are paid on produced oil and natural gas based upon a percentage of gross revenues or at fixed rates established by state or local taxing authorities. Our production and ad valorem taxes totaled $17.3 million, $2.1 million and $0.8 million for the years ended December 31, 2013, 2012 and 2011, respectively. The change in production and ad valorem taxes over the three year period was due to both the significant increase in production volumes as well as changes in our average realized prices for oil over the periods.

Depreciation, Depletion, Amortization, and Accretion. Depletion, depreciation, amortization, and accretion ("DD&A") reflects the systematic expensing of the capitalized costs incurred in the acquisition, exploration and development of oil and natural gas properties. We use the full-cost method of accounting and accordingly, we capitalize all costs associated with the acquisition, exploration and development of oil and natural gas properties, including unproved and unevaluated property costs. Internal costs are capitalized only to the extent they are directly related to acquisition, exploration and development activities and do not include any costs related to production, selling or general corporate administrative activities. Capitalized costs of oil and natural gas properties are amortized using the units of production method based upon production and estimates of proved oil and natural gas reserve quantities. Unproved and unevaluated property costs are excluded from the amortizable base used to determine depletion, depreciation and amortization expense. Our depletion, depreciation, amortization and accretion expenses increased from $4.2 million in 2011 and $15.9 million in 2012 to $134.8 million for the year ended December 31, 2013 due to increases in production and cost basis related to our recent acquisitions as well as significant development costs incurred.

General and Administrative Expenses. Our G&A expenses, including stock-based compensation, totaled $48.0 million for the year ended December 31, 2013 compared to $37.2 million and $5.4 million for the same periods in 2012 and 2011, respectively. G&A expenses, excluding stock-based compensation expense, totaled $30.2 million for 2013, an increase of 158% over the 2012 comparable period. This increase was due primarily to additional costs for added personnel of SOG performing services for the Company and for consulting services. For the year ended December 31, 2012, we recorded a non-cash stock-based compensation expense of approximately $25.5 million primarily related to the rescission and cancellation of 1.1 million shares of restricted stock during the second quarter of 2012. The restricted stock awards were granted to non-employees such that upon rescission and cancellation, stock-based compensation expense was based on the fair value at the date of cancellation, and the associated unrecognized compensation expense was accelerated and recognized as stock-based compensation expense. At the date of cancellation, the fair value of the stock awards cancelled was approximately $22.3 million, or $20.28 per restricted share.

Interest Expense. For the year ended December 31, 2013, interest expense totaled $30.9 million and included $6.9 million in amortization of debt issuance costs and write-offs of previously incurred debt issuance costs in connection with the termination of the Second Lien Term Credit Agreement and the commitment for the bridge loan credit facility, as well as in connection with the modification of the First Lien Credit Agreement during the period. The expense incurred is primarily related to the issuance of the Senior Notes issued during 2013. Interest expense for the year ended December 31, 2012 was $0.1 million and related to the First Lien Credit Agreement and Second Lien Term Credit Agreement.

Commodity Derivative Transactions. We apply mark-to-market accounting to our derivative contracts; therefore the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in other income and expense. During the year ended December 31, 2013, we recognized a total loss of $16.9 million on our commodity derivative contracts including a net loss of $5.8 million associated with the settlements of commodity derivative contracts and $2.8 million related to the premiums paid on derivative contracts. During the year ended December 31, 2012, we recognized a total loss of $0.7 million on our derivative contracts including a net gain of $2.7 million associated with the settlements of our derivative contracts offset by $3.1 million related to the premiums paid on derivative contracts. During the year ended December 31, 2011, we recognized a total loss of $0.5 million on our derivative contracts with no cash settlements.

Income tax expense. The properties contributed by SEP I were historically owned by a limited partnership that is not a taxable entity and is a disregarded entity for federal income tax purposes. Their taxable income or loss, which may vary substantially from the net income or loss reported in the

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consolidated statements of operations, was allocated to the limited and general partners of SEP I. With the transfer of the SEP I Assets to us, the SEP I Assets' operations were subject to federal and state income taxes. At the date of acquisition, we estimated that the aggregate net tax basis of the SEP I Assets exceeded the aggregate net book basis by $24.9 million, resulting in a deferred tax asset of $8.7 million, which was fully offset by a valuation allowance.

Effective December 19, 2011, we began accounting for income taxes using the asset and liability method. Deferred tax assets and liabilities arise from the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Valuation allowances are established when necessary to reduce the deferred tax asset to the amount more likely than not to be recovered. Management determined that it is more likely than not that its deferred tax assets will be realized and released the valuation allowance. For the year ended December 31, 2013, income tax expense totaled $4.0 million. Our 2013 effective rate was 12.91% compared to a statutory rate of 35% due primarily to the release of the valuation allowance. We expect our effective tax rate going forward to be approximately 35%.

Liquidity and Capital Resources

As of December 31, 2013, we had approximately $154 million in cash and cash equivalents and a $300 million unused, available borrowing base under our revolving credit facility with a group of ten participating banks, resulting in available liquidity of approximately $454 million.

We expect to use our cash on hand, our internally generated cash flow from operations, and proceeds from our First Lien Credit Facility to fund our 2014 capital expenditures.

On November 16, 2012, we and our subsidiaries, SEP Holdings III and Marquis LLC (collectively referred to with us as the "Original Borrowers"), entered into the Previous First Lien Credit Agreement, dated as of November 15, 2012, among the Original Borrowers, Capital One, National Association, and each of the other lenders party thereto. The Previous First Lien Credit Agreement provided for a $250 million revolving credit facility which was to mature November 16, 2015 and was secured by a senior lien on substantially all of the assets of the Original Borrowers. The borrowing base under the Previous First Lien Credit Agreement, initially set at $27.5 million, was increased to $95 million on February 21, 2013.

Also on November 16, 2012, we entered into the Second Lien Term Credit Agreement (the "Second Lien Term Credit Agreement"), dated as of November 15, 2012, among the Original Borrowers, Macquarie Bank Limited, and the other lenders party thereto. The Second Lien Term Credit Agreement provided for a $250 million term loan facility which was to mature May 16, 2016 and was secured by a lien on substantially all of the assets of the Original Borrowers that was junior to the liens on such assets under the Previous First Lien Credit Agreement. The Second Lien Term Credit Agreement provided for an initial commitment of $50 million, subject to conditions, with the remaining commitments subject to the approval of the lenders and other conditions. We borrowed $50 million under the Second Lien Term Credit Agreement in January 2013.

In connection with the purchase and sale agreement to purchase the Cotulla assets, the Company entered into commitment letters for $325 million in debt financing and issued the Series B Convertible Perpetual Preferred Stock. The $325 million in debt financing contemplated by the commitment letters consisted of an amendment and restatement of the Company's Previous First Lien Credit Agreement to increase the borrowing base from $95 million to $175 million and a $150 million bridge loan credit facility. Availability of the debt financing was conditioned upon, and was intended to be available concurrently with, the closing of the Cotulla acquisition and was subject to the satisfaction of various closing conditions. On May 30, 2013, the Company borrowed $90 million under its Previous First Lien Credit Agreement. The Company did not enter into a definitive agreement for the bridge loan credit facility and it was never activated.

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On May 31, 2013, the Original Borrowers and a new subsidiary of the Company, SN Cotulla Assets, LLC ("SN Cotulla") (collectively, the "Borrowers") entered into the Amended and Restated Credit Agreement (the "First Lien Credit Agreement") with Royal Bank of Canada as administrative agent and the other lenders party thereto.

The First Lien Credit Agreement amended and restated the Previous First Lien Credit Agreement in its entirety to renew, extend and rearrange the debt outstanding under the Previous First Lien Credit Agreement and to, among other things, (i) replace Capital One with Royal Bank of Canada as administrative agent and issuing bank, (ii) increase the maximum credit amount to $500 million, and (iii) increase the borrowing base to $175 million. The Borrowers' obligations under the First Lien Credit Agreement are secured by a first priority lien on substantially all of their assets and the assets of the Company's existing and future subsidiaries not designated as "unrestricted subsidiaries," including a first priority lien on all ownership interests in existing and future subsidiaries. Availability under the First Lien Credit Agreement is at all times subject to conditions and the then applicable borrowing base, which was initially set at $175 million and is subject to periodic redetermination. The borrowing base can be redetermined up or down by the lenders based on, among other things, an increase in the Borrowers' debt and their evaluation of the Company's oil and natural gas reserves. All borrowings under the First Lien Credit Agreement bear interest, at the option of the Borrowers, either at an alternate base rate or a eurodollar rate. The alternate base rate of interest is equal to the sum of (a) the greatest of (i) the administrative agent's U.S. "prime rate", (ii) the federal funds effective rate plus 1/2 of 1% and (iii) the one-month LIBO Rate multiplied by the statutory reserve rate, plus 1% and (b) the applicable margin. The eurodollar rate of interest is equal to the sum of (x) the LIBO Rate for the applicable interest period multiplied by the statutory reserve rate and (y) the applicable margin. As of December 31, 2013 the applicable margin varied from 0.50% to 1.50% for alternate base rate borrowings and from 1.50% to 2.50% for eurodollar borrowings, depending on the utilization of the borrowing base. Furthermore, as of December 31, 2013 the Borrowers were required to pay a commitment fee on the unused committed amount at a rate varying from 0.375% to 0.50% per annum, depending on the utilization of the borrowing base. Additionally, the First Lien Credit Agreement provides for the issuance of letters of credit, limited in the aggregate to the lesser of $20 million and the total availability thereunder. As of December 31, 2013, there were no letters of credit outstanding.

The First Lien Credit Agreement contains various covenants and events of default that limit the Borrowers' ability to, among other things, incur indebtedness, make restricted payments, grant liens, consolidate or merge, dispose of certain assets, make certain investments, engage in transactions with affiliates and hedge transactions and make certain acquisitions. Furthermore, the First Lien Credit Agreement contains financial covenants that require the Borrowers to satisfy certain specified financial ratios, including (i) current assets to current liabilities of at least 1.0 to 1.0 and (ii) net debt to consolidated EBITDA of not greater than 4.0 to 1.0. Upon an event of default, the lenders may elect to accelerate the amounts due under the First Lien Credit Agreement. The obligations under the First Lien Credit Facility are guaranteed by all of the Company's existing and future subsidiaries not designated as "unrestricted subsidiaries." As of December 31, 2013, the Company was in compliance with the covenants of the First Lien Credit Agreement.

On May 31, 2013, the Company borrowed $96 million under its First Lien Credit Agreement. The Company used proceeds from this borrowing to repay the $90 million outstanding under the Previous First Lien Credit Agreement. On June 13, 2013, the Company used proceeds from its Senior Notes (as defined below) offering described below to repay the $96 million outstanding under the First Lien Credit Agreement and the $50 million outstanding under the Second Lien Term Credit Agreement. The Second Lien Term Credit Agreement was retired with no further availability. The borrowing base on the First Lien Credit Agreement was increased to $175 million as a result of the redetermination conducted by the banks based upon the Company's June 30, 2013 updated reserves and subsequently increased again to $300 million as a result of the redetermination conducted by the banks based upon

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the Company's September 30, 2013 updated reserves. On February 28, 2014, the Company entered into the Fifth Amendment to the First Lien Credit Agreement, the primary effect of which was the establishment of a $400 million approved borrowing base and the establishment of an elected commitment amount of $325 million. Further redeterminations of the borrowing base are scheduled to be effective on or before April 1 and October 1 of each year, commencing October 1, 2014. From time to time, the agents and lenders under the First Lien Credit Agreement and their affiliates have provided, and may provide in the future, investment banking, commercial lending, hedging and financial advisory services to the Company and its affiliates in the ordinary course of business, for which they have received, or may in the future receive, fees and commissions for these transactions.

On June 13, 2013, the Company completed a private offering of $400 million in aggregate principal amount of the Company's 7.75% senior notes that will mature on June 15, 2021 (the "Original Notes"). Interest is payable on each June 15 and December 15. The Company received net proceeds from this offering of approximately $388 million, after deducting initial purchasers' discounts and estimated offering expenses, which the Company used to repay all of the approximately $96 million in borrowings outstanding under its First Lien Credit Agreement and to retire the Second Lien Term Credit Agreement by repaying the $50 million in borrowings outstanding. The Original Notes are the senior unsecured obligations of the Company and are guaranteed on a joint and several senior unsecured basis by, with certain exceptions, substantially all of the Company's existing and future subsidiaries. The borrowing base under the Company's First Lien Credit Agreement was reduced to $87.5 million upon issuance of the Original Notes, and was later increased to $300 million, all of which is available for future revolver borrowings as of December 31, 2013.

On September 18, 2013, the Company issued an additional $200 million in aggregate principal amount of its 7.75% senior notes due 2021 (the "Additional Notes" and, together with the Original Notes, the "Senior Notes") in a private offering at a price to the purchasers of 96.5% of the Additional Notes. The Company received net proceeds from this offering of approximately $188.8 million, after deducting the initial purchasers' discounts and estimated offering expenses of approximately $4.2 million. The Additional Notes were issued under the same indenture as the Original Notes, and are therefore treated as a single class of securities under the indenture. The Company used the net proceeds from the offering to partially fund the acquisition of Wycross acquisition completed in October 2013 and a portion of the 2013 capital budget, and intends to use the remaining proceeds to fund a portion of the 2014 capital budget and for general corporate purposes.

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

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

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The Company has the option to redeem all or a portion of the Senior Notes, at any time on or after June 15, 2017 at the applicable redemption prices specified in the indenture plus accrued and unpaid interest. The Company may also redeem the Senior Notes, in whole or in part, at a redemption price equal to 100% of their principal amount plus a make whole premium, together with accrued and unpaid interest and additional interest, if any, to the redemption date, at any time prior to June 15, 2017. In addition, the Company may redeem up to 35% of the Senior Notes prior to June 15, 2016 under certain circumstances with the net cash proceeds from certain equity offerings at the redemption price specified in the indenture. The Company may also be required to repurchase the Senior Notes upon a change of control.

On March 26, 2013, the Company completed a private placement of 4,500,000 shares of Series B Convertible Perpetual Preferred Stock. The issue price of each share of the Series B Convertible Perpetual Preferred Stock was $50.00. The Company received net proceeds from the private placement of approximately $216.6 million, after deducting placement agent's fees and offering costs of approximately $8.4 million.

On September 18, 2013, the Company completed a public offering of 11,040,000 shares of common stock (including 1,440,000 shares purchased pursuant to the full exercise of the underwriters' overallotment option), at an issue price of $23.00. The Company received net proceeds from this offering of approximately $241.5 million, after deducting underwriters' fees and offering expenses of approximately $12.4 million. The Company used the net proceeds from the offering to partially fund the Wycross acquisition, completed in October 2013, to fund a portion of the 2013 capital budget, and intends to use the remaining proceeds to fund a portion of the preliminary 2014 capital budget, and for general corporate purposes.

Cash Flows

Our cash flows for the years ended December 31, 2013, 2012 and 2011 are as follows (in thousands):

	Year Ended December 31,		
	2013	**2012**	**2011**
Cash Flow Data:			
Net cash provided by operating activities	$ 189,261	$ 29,072	$ 5,546
Net cash used in investing activities	$ (1,093,363)	$ (181,427)	$ (108,005)
Net cash provided by financing activities	$ 1,007,286	$ 139,661	$ 165,500

Net Cash Provided by Operating Activities. Net cash provided by operating activities in 2013 was approximately $189.3 million compared to a $29.1 million in 2012 and $5.5 million in 2011. The increase in net cash provided by operating activities in 2013 as compared to 2012 was due to a $22.1 million increase in accounts payable and accrued liabilities from increased operational activity in 2013, a $118.9 million increase in DD&A expense due to a significantly higher amortization base and increased production during 2013, a $7.1 million increase in deferred financing cost amortization from various financing activity during 2013, a $4.0 million increase in income tax expense, and a net income in 2013 that was $43.2 million greater than in 2012. This was offset by a $38.7 million increase in accounts receivable and a decrease in stock based compensation expense of $7.8 million as compared to the respective prior year period. The remaining $11.4 million increase related primarily to derivative activity between the periods.

Net Cash Used in Investing Activities. Net cash flows used in investing activities totaled approximately $1,093.4 million for the year ended December 31, 2013 compared to $181.4 million for the year ended December 31, 2012 and $108.0 million for the same period in 2011. For the year ended December 31, 2013, capital expenditures for leasehold and drilling activities totaled $479.9 million, primarily associated with the drilling of 53 net wells. We paid cash of approximately $623.0 million for the oil and natural gas properties acquired in the Cotulla acquisition, the TMS transactions, the Wycross acquisition as well as other less material acquisitions of oil and natural gas properties. In addition, we invested $2.1 million in computers and other equipment. Partially offsetting these costs were proceeds of $11.6 million from the sale of marketable securities. In 2012, we made capital expenditures for leasehold and drilling activities of $169.7 million, primarily associated with the drilling of 20 wells, and invested $11.6 million in marketable securities. In 2011, we acquired the Marquis Assets which used cash of $89.0 million and incurred capital expenditures for leasehold and drilling activities of $20.6 million. This was partially offset by $1.6 million in proceeds from the sale of certain non-core undeveloped leases.

Net Cash Provided by Financing Activities. Net cash flows provided by financing activities totaled approximately $1.0 billion for the year ended December 31, 2013 compared to $140.0 million for the year ended December 31, 2012. During the year ended December 31, 2013, we received net proceeds from the private placement of preferred stock of approximately $216.6 million, after deducting placement agent's fees and offering costs payable by us of approximately $8.4 million. We also received net proceeds of approximately $577.0 million from the private placement of our Senior Notes, consisting of face value of $600 million, including the Additional Notes which were issued at a discount to face value of $7.0 million, less debt issuance costs of approximately $16.0 million, included in the $24.1 million discussed below. During the third quarter of 2013, the Company completed a public offering of common stock, and received net proceeds from this offering of approximately $241.4 million, after deducting underwriter's fees and other expenses of approximately $12.5 million. During the first quarter of 2013, we borrowed $50 million under our Second Lien Term Credit Agreement. On May 30, 2013, we borrowed $90 million under our Previous First Lien Credit Agreement. On May 31, 2013, we borrowed $96 million under our First Lien Credit Agreement, and used the proceeds to repay the $90 million borrowed under our Previous First Lien Credit Agreement. The outstanding borrowings under our First Lien Credit Agreement and Second Lien Term Credit Agreement were repaid during the second quarter of 2013 with proceeds from the offering of the Original Notes. Other financing costs for the year ended December 31, 2013 included $24.1 million for debt issuance costs, $18.5 million paid for preferred stock dividends and $1.1 million paid for the purchase of common stock to settle taxes on the vesting of employee stock grants.

For the year ended December 31, 2012, net cash flows provided by financing activities totaled $139.7 million due primarily to net proceeds from our private placement of Convertible Perpetual Preferred Stock of approximately $144.5 million, after deducting the initial purchasers' discounts and commissions and offering costs payable by us of approximately $5.5 million. These net proceeds were partially offset by financing costs associated with our new credit facilities of $2.7 million and preferred dividends paid of $2.1 million. For the year ended December 31, 2011, net cash flows provided by financing activities totaled $165.5 million due primarily to our IPO. We received net proceeds of approximately $203.3 million from the sale of the shares of common stock (net of expenses and underwriting discounts and commissions). With proceeds from the IPO, we paid SEP I $50.0 million and paid for the acquisition of the Marquis Assets. Partially offsetting these payments were contributions by SEP I of $12.2 million related to the operation of the oil and natural gas properties prior to our acquisition of the SEP I Assets.

Commitments and Contractual Obligations

As of December 31, 2013, our contractual obligations included our Senior Notes, interest expense on our Senior Notes, deferred premiums on our commodity hedging contracts, and asset retirement obligations. The material changes in our contractual obligations during the twelve months ended December 31, 2013 included (i) the repayment of all of the approximately $96 million in borrowings outstanding under our First Lien Credit Agreement, (ii) the retirement of our Second Lien Term

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Credit Agreement by repaying in full the $50 million in borrowings outstanding thereunder, (iii) the issuance of our Senior Notes, and (iv) the recognition of asset retirement obligations related to our properties. In addition, in connection with the TMS transactions, the Company has committed to carry SR for its 50% working interest in an initial 3 gross (1.5 net) TMS wells to be drilled within the AMI. At the Company's election, it may carry SR in an additional 3 gross (1.5 net) TMS wells if it desires to participate in additional drilling within the AMI. The following table summarizes our contractual obligations as of December 31, 2013 (in thousands):

	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
Senior Notes	$	$	$	$ 600,000	$ 600,000
Interest expense(1)	46,500	93,000	93,000	116,250	348,750
Derivative liabilities(2)	766	5,012			5,778
Asset retirement obligations(3)				4,130	4,130
Total	$ 47,266	$ 98,012	$ 93,000	$ 720,380	$ 958,658

(1) Represents estimated interest payments that will be due under the 7.750% $600 million Senior Notes that will mature on June 15, 2021.

(2) Represents payments due for deferred premiums on our commodity hedging contracts, including amounts due but not yet paid. See *Note 11 Derivative Instruments* in the *Notes to the Consolidated Financial Statements* under Item 8 of this Form 10-K.

(3) Amounts represent our estimate of future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See *Note 13 Asset Retirement Obligations* in the *Notes to the Consolidated Financial Statements* under Item 8 of this Form 10-K.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements that have been prepared in accordance with GAAP. The preparation of these consolidated financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in Note 2 to our consolidated financial statements. See Note 2 "Basis of Presentation and Summary of Significant Accounting Policies" in the notes to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" of this Annual Report on Form 10-K. When we prepare our financial statements, we review our estimates, including those related to oil, NGL and natural gas revenues, oil and natural gas properties, oil, NGL and natural gas reserves, fair value of derivative instruments, abandonment liabilities, income taxes, commitments and contingencies, depreciation, depletion and amortization, and full cost ceiling calculation. Our estimates are based on historical experience and various assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements.

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Oil and Natural Gas Properties

The Company's oil and natural gas properties are accounted for using the full cost method of accounting. All direct costs and certain indirect costs associated with the acquisition, exploration and development of oil and natural gas properties are capitalized. Once evaluated, these costs, as well as the estimated costs to retire the assets, are included in the amortization base and amortized to depletion expense using the units-of-production method. Depletion is calculated based on estimated proved oil and natural gas reserves. Proceeds from the sale or disposition of oil and natural gas properties are applied to reduce net capitalized costs unless the sale or disposition causes a significant change in the relationship between costs and the estimated quantities of proved reserves.

Full Cost Ceiling Test Capitalized costs (net of accumulated depreciation, depletion and amortization and deferred income taxes) of proved oil and natural gas properties are subject to a full cost ceiling limitation. The ceiling limits these costs to an amount equal to the present value, discounted at 10%, of estimated future net cash flows from estimated proved reserves less estimated future operating and development costs, abandonment costs (net of salvage value) and estimated related future income taxes. In accordance with Securities and Exchange Commission ("SEC") rules, the oil and natural gas prices used to calculate the full cost ceiling are the 12-month average prices, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. Prices are adjusted for "basis" or location differentials. Prices are held constant over the life of the reserves. If unamortized costs capitalized within the cost pool exceed the ceiling, the excess is charged to expense and separately disclosed during the period in which the excess occurs. Amounts thus required to be written off are not reinstated for any subsequent increase in the cost center ceiling. No impairment expense was recorded for the years ended December 31, 2013, 2012 or 2011.

Depreciation, depletion and amortization DD&A is provided using the units-of-production method based upon estimates of proved oil, NGL and natural gas reserves with oil, NGL and natural gas production being converted to a common unit of measure based upon their relative energy content. All capitalized costs of oil and natural gas properties, including the estimated future costs to develop proved reserves, are amortized using the units-of-production method based on total proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Once the assessment of unproved properties is complete and when major development projects are evaluated, the costs previously excluded from amortization are transferred to the full cost pool and amortization begins. The amortizable base includes estimated future development costs and where significant, dismantlement, restoration and abandonment costs, net of estimated salvage value.

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

Unproved Properties Costs associated with unproved properties and properties under development are excluded from the full cost amortization base until the properties have been evaluated. Additionally, the costs associated with seismic data, leasehold acreage, and wells currently drilling are also initially excluded from the amortization base. Unproved properties are identified on a project

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basis, with a project being an area in which significant leasehold interests are acquired within a contiguous area. Unproved properties are reviewed periodically by management and transferred into the full cost pool subject to amortization when management determines that a project area has been evaluated through drilling operations or a thorough geologic evaluation.

Oil and Natural Gas Reserves

The Company's most significant estimates relate to its proved oil and natural gas reserves. The estimates of oil and natural gas reserves as of December 31, 2013, 2012 and 2011 are based on reports prepared by a third party engineering firm, Ryder Scott Company, L.P. ("Ryder Scott").

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

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

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

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

Asset Retirement Obligations

We comply with ASC 410-20 and recognize estimated amounts for asset retirement obligations and asset retirement costs. ASC 410-20 requires liability recognition for retirement obligations associated with tangible long-lived assets, such as producing well sites. The obligations included within the scope of ASC 410-20 are those for which we face a legal obligation for settlement. The initial measurement of the asset retirement obligation is fair value, defined as "the price that an entity would have to pay a willing third party of comparable credit standing to assume the liability in a current transaction other than in a forced or liquidation sale." The significant unobservable inputs to this fair value measurement include estimates of plugging, abandonment, remediation costs, well life, inflation and credit-adjusted risk free rate. The inputs are calculated based on historical data as well as current estimates. When the liability is initially recorded, we increase the carrying amount of the related long-lived asset. Over time, accretion of the liability is recognized each period, and the capitalized cost is amortized over the useful life of the related asset. Upon settlement of the liability, the obligation is either settled for its recorded amount or a gain or loss is incurred which we treat as an adjustment to the full cost pool. The standard requires us to record a liability for the fair value of the dismantlement and abandonment costs, excluding salvage values.

Stock-Based Compensation

The Company records stock-based compensation expense for awards granted to its directors (for their services as directors) in accordance with the provisions of ASC 718, "*Compensation Stock Compensation*." Stock-based compensation expense for these awards is based on the grant-date fair value and recognized over the vesting period using the straight-line method.

Awards granted to employees of the Sanchez Group (including those employees of the Sanchez Group who also serve as the Company's officers) and consultants in exchange for services are considered awards to non-employees and the Company records stock-based compensation expense for these awards at fair value in accordance with the provisions of ASC 505-50, "*Equity-Based Payments to Non-Employees*." For awards granted to non-employees, the Company records compensation expenses equal to the fair value of the stock-based award at the measurement date, which is determined to be the earlier of the performance commitment date or the service completion date. Compensation expense for unvested awards to non-employees is revalued at each period end and is amortized over the vesting period of the stock-based award. Stock-based payments are measured based on the fair value of the equity instruments granted, as it is more determinable than the value of the services rendered.

Revenue Recognition

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

Derivative Instruments

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

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

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

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

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Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil, NGL and natural gas production. Realized pricing is primarily driven by the prevailing market prices applicable to our natural gas and oil production. Pricing for oil, NGL and natural gas has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. The prices we receive for our oil, NGL and natural gas production depend on many factors outside of our control, such as the strength of the global economy.

To reduce the impact of fluctuations in oil and natural gas prices on our revenues, or to protect the economics of property acquisitions, we periodically enter into derivative contracts with respect to a portion of our projected oil and natural gas production through various transactions that fix or, through options, modify the future prices realized. These transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pays the excess, if any, of the floating rate over the fixed ceiling price. In addition, we enter into option transactions, such as puts or put spreads, as a way to manage our exposure to fluctuating prices. These hedging activities are intended to support oil and natural gas prices at targeted levels and to manage exposure to oil and natural gas price fluctuations. We do not enter into derivative contracts for speculative trading purposes.

As of December 31, 2013, we had the following crude oil swaps, collars and put spreads covering anticipated future production as indicated below:

Contract Period	Derivative Instrument	Barrels	Purchased	Sold	Pricing Index
January 1, 2014 - June 30, 2014	Swap	90,500	$ 97.19	n/a	NYMEX WTI
January 1, 2014 - December 31, 2014	Swap	273,750	$ 92.00	n/a	NYMEX WTI
January 1, 2014 - December 31, 2014	Swap	273,750	$ 91.35	n/a	NYMEX WTI
January 1, 2014 - December 31, 2014	Swap	273,750	$ 92.45	n/a	NYMEX WTI
January 1, 2014 - December 31, 2014	Swap	365,000	$ 95.45	n/a	NYMEX WTI
January 1, 2014 - December 31, 2014	Swap	365,000	$ 93.25	n/a	NYMEX WTI
January 1, 2015 - December 31, 2015	Swap	365,000	$ 89.65	n/a	NYMEX WTI
January 1, 2015 - December 31, 2015	Swap	365,000	$ 90.05	n/a	NYMEX WTI
January 1, 2014 - December 31, 2014	Collar	365,000	$ 90.00	$ 99.10	NYMEX WTI
July 1, 2014 - December 31, 2014	Put Spread	184,000	$ 90.00	$ 75.00	NYMEX WTI

As of December 31, 2013, we had the following natural gas swaps and collars covering anticipated future production as indicated below: