

Sanchez Energy Corp  
Form 10-K  
March 18, 2013

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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**

(Mark One)

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

For the fiscal year ended December 31, 2012

OR

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

For the transition period from \_\_\_\_\_ to \_\_\_\_\_  
Commission file number: 1-35372

**Sanchez Energy Corporation**

(Exact name of registrant as specified in its charter)

**Delaware**  
(State or other jurisdiction of  
incorporation or organization)

**45-3090102**  
(I.R.S. Employer Identification No.)

**1111 Bagby Street, Suite 1800**  
**Houston, Texas**  
(Address of principal executive offices)

**77002**  
(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) Common Stock, par value \$0.01 per share (Name of Exchange) New York Stock Exchange

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

None

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

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

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes  No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes  No

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer  Accelerated filer  Non-accelerated filer  Smaller reporting company

(Do not check if a  
smaller reporting company)

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2012: \$569,169,307

Number of shares of registrant's common stock outstanding as of March 15, 2013: 34,589,698.

### Documents Incorporated By Reference:

Portions of the registrant's definitive proxy statement for its 2013 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2012, are incorporated by reference into Part III of this report for the year ended December 31, 2012.

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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.

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**SANCHEZ ENERGY CORPORATION**  
**FORM 10-K**  
**FOR THE YEAR ENDED DECEMBER 31, 2012**  
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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, 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, including the consummation of the transactions contemplated by the purchase and sale agreement we entered into with Hess Corporation, or Hess, on March 18, 2013 (referred to herein as the "Hess acquisition");

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

the realized benefits of the acquisition of SN Marquis LLC, or Marquis LLC, and the proposed Hess acquisition and liabilities assumed in connection with the acquisition and the proposed Hess 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;

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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Sanchez Energy Corporation (together with our consolidated subsidiaries, the "company," "we," "our," "us" or similar terms) is an independent exploration and production company focused on the exploration, acquisition and development of unconventional oil and natural gas resources in the Eagle Ford Shale in South Texas. As of December 31, 2012, we had accumulated approximately 95,000 net leasehold acres in the oil and condensate, or black oil and volatile oil, windows of the Eagle Ford Shale in Gonzales, Zavala, Frio, Fayette, Lavaca, Atascosa, Webb and DeWitt Counties of South Texas. 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."

Our Eagle Ford Shale acreage is comprised of approximately 9,700 net acres in Gonzales County, Texas, which we refer to as our Palmetto area, approximately 28,400 net acres in Zavala and Frio Counties, Texas, which we refer to as our Maverick area, and approximately 57,100 net acres in Fayette, Lavaca, Atascosa, Webb and DeWitt Counties of South Texas, which we refer to as our Marquis area. We own all rights and depths on the majority of our Eagle Ford Shale acreage. We believe this acreage to be prospective for other zones, including the Buda Limestone, Austin Chalk and Pearsall Shale formations that lie above and below the Eagle Ford Shale. We are currently evaluating these other zones, which may present us with additional drilling locations. Several of our existing wells are either producing from or have logged pay in the Buda Limestone and the Austin Chalk formations.

Our estimated proved reserve information as of December 31, 2012 is based on a report prepared by Ryder Scott Company, L.P., or Ryder Scott, our independent reserve engineers. The following table presents summary data for each of our primary project areas as of December 31, 2012 and our capital expenditure budget for the 2013 fiscal year:

	Net Acreage	Identified Drilling Locations(1)		2013 Capital Expenditure Budget			Estimated Net Proved Reserves(2) (mmboe)
		Gross	Net	Gross Wells	Net Wells	Drilling Capex (in millions)	
Palmetto Gonzales(3)	9,670	237	113	25	12.5	\$ 125	17.7
Maverick Zavala, Frio	28,436	264	230	2	2.0	12	0.6
Marquis Fayette, Lavaca, Atascosa, Webb and DeWitt	57,076	472	472	19	19.0	190	2.9
Total Eagle Ford Shale	95,182	973	815	46	33.5	327	21.2
Other	83,249	46	11				
Total	178,431	1,019	826	46	33.5	\$ 327	21.2

(1) Total identified drilling locations are calculated using approximately 120 acre well-spacing for our Maverick and Marquis areas and approximately 80 acre well-spacing for our Palmetto area in the Eagle Ford.

(2) Based on Ryder Scott estimated proved reserve report as of December 31, 2012.

(3)



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In our Palmetto area, we have 106 gross (53 net) locations that are classified as proved undeveloped at December 31, 2012. We plan to drill all of those proved undeveloped locations within the next five years.

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**Recent Developments**

On March 18, 2013, we executed a definitive agreement to purchase assets in the Eagle Ford Shale in South Texas from Hess for approximately \$265 million in cash, subject to customary adjustments. The effective date of the transaction is March 1, 2013 with an expected closing date in the second quarter. The proposed acquisition includes (based on the Company's internal estimates) estimated proved reserves, as of the effective date, of 13.4 mmboe, 70% oil and 30% natural gas. Proved developed reserves are estimated to account for approximately 50% of the total proved reserves. As of the effective date, the properties to be acquired consisted of approximately 43,000 net acres in Dimmit, Frio, LaSalle and Zavala Counties of South Texas with 50 gross wells currently producing approximately 4,500 boe/d.

In connection with the acquisition we have secured commitments for \$325 million in debt financing and expect to access the capital markets in the near term, subject to market conditions and other factors. Closing of the acquisition and availability of the debt financing are expected to occur concurrently in the second quarter of this year and will be subject to the satisfaction of various customary closing conditions.

**Our History**

We are a Delaware corporation formed in August 2011 to explore, acquire and develop unconventional oil and natural gas assets. In December 2011, we completed our IPO and concurrently closed or entered into the following transactions:

Sanchez Energy Partners I, LP, or SEP I (a member of the Sanchez Group (as defined below)), contributed to us 100% of the limited liability company interests in SEP Holdings III, LLC, or 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. In exchange for the limited liability company interests in SEP Holdings III, we paid SEP I \$50 million from the proceeds of the IPO and issued to SEP I 22,090,909 shares of our common stock. As a result of this transaction, SEP I became our largest stockholder at the time, holding approximately 66.9% of our outstanding common stock immediately following the completion of our IPO and the related transactions. On June 19, 2012 and September 17, 2012, SEP I distributed substantially all of the shares that it received in the IPO to its partners.

We acquired 100% of the limited liability company interests in Marquis LLC, which owns unevaluated properties in Fayette, Lavaca, Atascosa, Webb and DeWitt Counties of South Texas. In exchange for the limited liability company interests in Marquis LLC, we paid Ross Exploration, Inc., or Ross Exploration, approximately \$89 million in cash from the proceeds of the IPO and issued to Ross Exploration 909,091 shares of our common stock. The acreage that we acquired is subject to an overriding royalty interest that was previously conveyed by Ross Exploration to one of its affiliates.

We entered into a services agreement, or the Services Agreement, and other related agreements with Sanchez Oil & Gas Corporation, or SOG (together with its affiliates (excluding us but including SEP I), collectively referred to as members of the "Sanchez Group"). SOG is headquartered in Houston, Texas and is a private, full service oil and natural gas company engaged in the exploration and development of oil and natural gas primarily in the South Texas and onshore Gulf Coast areas on behalf of its affiliates. Pursuant to the Services Agreement, SOG (directly or through its subsidiaries) agreed to provide us with the services and data that we believe are necessary to manage, operate and grow our business, and we agreed to reimburse SOG for all direct and indirect costs incurred on our behalf. For a discussion of the Services Agreement, please read Note 9 "Related Party Transactions" in the notes to the consolidated

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financial statements in "Item 8. Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

We refer to the assets that we acquired through our acquisition of the limited liability company interests in SEP Holdings III as the "SEP I Assets" and the assets that we acquired through our acquisition of the limited liability company interests in Marquis LLC as the "Marquis Assets."

### **Our Business Strategies and Competitive Strengths**

Our primary business objective is to increase stockholder value by building reserves, production and cash flows at an attractive return on invested capital. To achieve our objective, we intend to execute the following business strategies:

*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, 2012, 82.5% of our reserves were proved undeveloped, or PUD, and the up to 973 gross (815 net) locations for potential future drilling that we have identified in our Eagle Ford Shale area will be our primary targets in the near term. We believe the Eagle Ford Shale to be the highest rate of return project that we currently possess. We anticipate drilling 46 gross (33.5 net) wells through December 2013 with an aggregate drilling and completion capital expenditure budget of approximately \$327 million.

*Pursue Strategic Acquisitions and 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. By leveraging the Sanchez Group's longstanding relationships in South Texas, we plan on continuing to expand our Eagle Ford Shale acreage position at what we believe to be attractive valuations. We also plan to selectively target additional domestic basins that would allow us to employ our strategies on large undeveloped acreage positions similar to our Eagle Ford Shale acreage.

*Leverage our Relationship with Our Affiliates to Expand Unconventional Oil Assets.* Various members of the Sanchez Group have drilled or participated in over 900 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 their relationships with mineral and surface rights owners in and around our South Texas and onshore Gulf Coast 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, to the extent relating to our properties, for our benefit. The majority of the database covers the South Texas and onshore Gulf Coast areas and includes more than 6,400 square miles of 3D seismic data and 47,800 miles of 2D seismic data used for regional interpretation, 435,300 well logs, 16,900 LAS files and 34,900 scanned well documents, as well as a fully integrated suite of the latest interpretive geologic software. We plan on leveraging 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.

*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 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.

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*Adopt and Employ Leading Drilling and Completion Techniques.* We are focused on enhancing our drilling and completion techniques to maximize recovery. Industry techniques with respect to drilling and completion have significantly evolved over the last several years, resulting in increased initial production rates and recoverable hydrocarbons per well through the implementation of longer laterals and more tightly spaced fracturing 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.

*Maintain Substantial Financial Liquidity to Capitalize on Opportunity and Limit Commodity Price Volatility.* As of December 31, 2012, we had approximately \$50.3 million in cash, \$11.6 million invested in available-for-sale securities and no indebtedness. We believe this strong liquidity position, combined with our cash flow from operations and the expected increased borrowing capacity under our credit facilities will allow us to continue to execute a capital expenditure program that should result in steady growth of production and proved reserves.

**Core Properties**

***Eagle Ford Shale***

The Eagle Ford Shale is one of the fastest growing unconventional shale trends in North America. According to the Smith Weekly Rig Count, the rig count in the Eagle Ford Shale grew 696% from 28 rigs in January 2010 to 223 rigs as of December 28, 2012. Based on a recent study by the Society of Petroleum Engineers, the aerial extent of the trend is thought to be approximately 11 million acres.

In the Eagle Ford Shale, we have assembled approximately 95,000 net acres with an average working interest of approximately 87%. Using approximately 120 acre well-spacing for our Maverick and Marquis areas and approximately 80 acre well-spacing for our Palmetto area, we believe that there could be up to 973 gross (815 net) locations for potential future drilling on our acreage. We also believe that continued down-spacing in our areas of operation will provide superior recoveries of oil in place and could materially increase our total inventory of drilling locations. Consistent with other operators in this area, we plan to perform multi-stage hydraulic fracturing up to 25 stages on each well depending upon the length of the lateral section. Through December 2013, we plan to spend approximately \$327 million on drilling 46 gross (33.5 net) wells on our Eagle Ford Shale acreage.

In our Palmetto area, we have approximately 9,700 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 16 gross wells on our acreage that had an average initial 24-hour production rates between 502 and 3,139 boe/d. We have identified up to 237 gross (113 net) locations based on 80 acre well-spacing for potential future drilling in our Palmetto area. We are drilling a five-well pilot program from a single pad to test 40 acre well-spacing in our southern portion of the Palmetto area, and Ryder Scott has given us 80 acre well-spaced PUD locations in the same area in its December 31, 2012 reserve report. Through December 2013, we plan to spend approximately \$125 million to drill 25 gross (12.5 net) wells in our Palmetto area.

In our Maverick area, we have approximately 28,400 net operated acres in Zavala and Frio Counties, Texas with an average working interest of approximately 87%. We believe that our Maverick acreage lies in the black oil window, where we anticipate drilling, completion and facilities costs on our acreage to be between \$5.5 million and \$6.5 million per well based on our historical well costs and publicly available information. We have drilled ten gross horizontal wells that had a range of average initial 24-hour production rates between 214 and 931 boe/d. We have also drilled four vertical wells that had average initial 24-hour rates between 94 and 264 boe/d. We will continue to test the feasibility of a

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vertical well development program and compare horizontal and vertical completion economic returns. We have identified up to 264 gross (230 net) locations based on 120 acre well-spacing for potential future drilling on our Maverick acreage. Through December 2013, we plan to spend approximately \$12 million to drill 2 gross (2 net) wells in our Maverick area.

In our Marquis area, we have approximately 57,100 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 \$7.5 million and \$11.0 million per well based on our historical well costs and publicly available information. We have drilled three horizontal wells that had a range of average initial 24-hour production rates between 1,114 and 1,369 boe/d. We have identified up to 472 gross and net locations based on 120 acre well-spacing for potential future drilling on our Marquis acreage. We are also drilling a 60 acre well-spacing test in the western Prost area of our Marquis area. Through December 2013, we plan to spend approximately \$190 million to drill 19 gross (19 net) wells in our Marquis area.

### *Other*

In addition, we have approximately 1,000 net acres in the Haynesville Shale in Natchitoches Parish, Louisiana, which are operated by Chesapeake Energy Corporation. We do not currently anticipate spending any capital on our Haynesville acreage in the near future. The majority of our Haynesville leases are held by production, giving us and our partners the option to accelerate drilling should natural gas prices increase.

Finally, we have amassed approximately 82,000 net acres in northern Montana, which we believe may be prospective for the Heath, Three Forks and Bakken Shales. Our lease terms in northern Montana are for five years with an option in 2013 to renew for another five years at \$10 per acre, giving us time to allow the industry activity to develop the trend before we devote significant drilling capital to our acreage position.

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.

### **Oil and Natural Gas Reserves and Production**

#### *Internal Controls*

Our estimated reserves at December 31, 2012 were prepared by 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

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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.

See " Estimated Probable and Possible Reserves" for additional information regarding probable and possible reserves.

***Qualifications of Responsible Technical Persons***

*Internal SOG Person.* Vinodh Kumar is the technical person primarily responsible for overseeing the preparation of our reserve estimates. Mr. Kumar is also responsible for liaison with and oversight of our third-party reserve engineers. 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.

*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.

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***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, 2012, 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, 2012
<b>Reserve Data(1):</b>	
Estimated proved reserves:	
Oil (mbo)	18,266
Natural gas liquids (mdbl)	310
Natural gas (mmcf)	15,788
Total estimated proved reserves (mboe)(2)	21,207
Estimated proved developed reserves:	
Oil (mbo)	3,211
Natural gas liquids (mdbl)	99
Natural gas (mmcf)	2,433
Total estimated proved developed reserves (mboe)(2)	3,716
Estimated proved undeveloped reserves:	
Oil (mbo)	15,055
Natural gas liquids (mdbl)	211
Natural gas (mmcf)	13,355
Total estimated proved undeveloped reserves (mboe)(2)	17,491
Standardized Measure (in millions)(1)(3)	\$ 286.3

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- (1) Our estimated net proved reserves and related standardized measure were determined using index prices for oil and natural gas, without giving effect to commodity derivative contracts, held constant throughout the life of our properties. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were \$94.71/bo for oil, \$43.24/bbl for NGLs and \$2.76/mmbtu for natural gas at December 31, 2012. 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. As of December 31, 2012, the average realized prices for oil, NGLs and natural gas were \$101.40 per bo, \$23.26 per bbl and \$2.54 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 Statement of Financial Accounting Standards No. 69, Disclosures About Oil and Gas Producing Activities, as codified in





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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 internal 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, 2012 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 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."

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.

#### ***Estimated Probable and Possible Reserves***

Unless otherwise specifically identified in this Annual Report on Form 10-K, the summary data with respect to our estimated reserves has been prepared by our independent reserve engineers in accordance with rules and regulations of the SEC applicable to companies involved in oil and natural gas producing activities.

The reserve estimates at December 31, 2012 presented in the table below are based on a report prepared by Ryder Scott, our independent reserve engineers. For more information regarding our independent reserve engineers, please see "Qualifications of Responsible Technical Persons" above.

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The information in the following table does not give any effect to or reflect our commodity derivative instruments.

Estimates of probable reserves are inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, an estimated quantity of probable reserves is an estimate of those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Estimates of probable reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Estimates of possible reserves are also inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, an estimated quantity of possible reserves is an estimate that might be achieved, but only under more favorable circumstances than are likely. Estimates of possible reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserve where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir. Possible reserves also include incremental quantities associated with a greater percentage of recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are

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structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

Project Area	As of December 31, 2012(1)					
	Proved Reserves (mboe)(3)	PV-10(4) (in millions)	Probable Reserves(2) (mboe)(3)	PV-10(4) (in millions)	Possible Reserves(2) (mboe)(3)	PV-10(4) (in millions)
Eagle Ford						
Palmetto Gonzales	17,736	\$ 270.7	4,627	\$ 16.0	4,795	\$ 6.0
Maverick Zavala, Frio	554	24.1				
Marquis Fayette, Lavaca, Atascosa, Webb and DeWitt	2,917	65.5	1,943	10.2		
Total Eagle Ford Shale	21,207	360.3	6,570	26.2	4,795	6.0
Other						
Total	21,207	\$ 360.3	6,570	\$ 26.2	4,795	\$ 6.0

- (1) Our estimated net proved, probable and possible reserves and related PV-10 at December 31, 2012 were determined using index prices for oil and natural gas, without giving effect to commodity derivative contracts, held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were \$94.71/bo for oil, \$43.24/bbl for NGLs and \$2.76/mmbtu for natural gas. 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. As of December 31, 2012, the average realized prices for oil, NGLs and natural gas were \$101.40 per bo, \$23.26 per bbl and \$2.54 per mcf, respectively.
- (2) In addition to the estimated proved reserve report dated December 31, 2012, Ryder Scott provided us with a probable and possible reserve report as of December 31, 2012 for the Palmetto and Marquis areas. Probable and possible reserves included in the report totaled 11 mmboe and \$32.2 million in additional PV-10 value. Of these reserves, 83% were attributed to our Palmetto area and 17% were attributed to our Marquis area, and 5,614 mbo and 4,140 mbo were classified as oil, 4,572 mmcf and 3,933 mmcf were classified as natural gas and 194 mbo and zero were classified as NGLs, respectively. Estimates of probable and possible reserves that may potentially be recoverable through additional drilling or recovery techniques are by nature more uncertain than estimates of proved reserves and accordingly are subject to substantially greater risk of not actually being realized by us. All of our probable and possible reserves are classified as undeveloped.
- (3) 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.
- (4) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved crude oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows and using the twelve-month unweighted arithmetic average of the first-day-of-the-month price for each of the preceding twelve months. PV-10 differs from the Standardized Measure because it does not include the effect of future income taxes. For a reconciliation of our Standardized Measure to PV-10, see " Reconciliation of PV-10 to Standardized Measure."

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***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.

The following table provides a reconciliation of PV-10 to the Standardized Measure at December 31, 2012 for our proved, probable and possible reserves (in millions):

	<b>Reserves</b>		
	<b>Proved</b>	<b>Probable</b>	<b>Possible</b>
PV-10	\$ 360.3	\$ 26.2	\$ 6.0
Present value of future income taxes discounted at 10%	(74.0)	(9.2)	(2.1)
Standardized Measure(1)	\$ 286.3	\$ 17.0	\$ 3.9

- 
- (1) Standardized measure is calculated in accordance with Statement of Financial Accounting Standards No. 69, Disclosures About Oil and Gas Producing Activities, as codified in 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 and natural gas and certain price and cost information attributable to our properties for each of the periods presented:

	Year Ended December 31,		
	2012	2011	2010
<b>Production:</b>			
<b>Oil mbo</b>			
Palmetto	262.7	132.2	43.4
Maverick	87.8	13.7	12.4
Marquis	67.4		
Other			
<b>Total</b>	<b>417.9</b>	<b>145.9</b>	<b>55.8</b>
<b>Natural gas liquids mbbl</b>			
Palmetto	0.6	0.5	
Maverick	0.1		
Marquis			
Other			
<b>Total</b>	<b>0.7</b>	<b>0.5</b>	
<b>Natural gas mmcf</b>			
Palmetto	226.7	104.5	31.9
Maverick			
Marquis			
Other	74.5	59.6	
<b>Total</b>	<b>301.2</b>	<b>164.1</b>	<b>31.9</b>
<b>Net production volumes:</b>			
Total oil equivalent (mboe)	468.8	173.7	61.1
Average daily production (boe/d)	1,280.8	475.9	167.4
<b>Average Sales Price:</b>			
Oil (\$ per bo)(1)	\$ 101.40	\$ 95.31	\$ 78.92
Natural gas liquids (\$ per bbl)	\$ 23.26	\$ 47.62	\$
Natural gas (\$ per mcf)	\$ 2.54	\$ 3.59	\$ 4.68
Oil equivalent (\$ per boe)(1)	\$ 92.07	\$ 83.57	\$ 74.50
<b>Average unit costs per boe:</b>			
Oil and natural gas production expenses	\$ 7.26	\$ 9.37	\$ 6.41
Production and ad valorem taxes	\$ 4.53	\$ 4.78	\$ 3.50
General and administrative(2)	\$ 24.95	\$ 30.91	\$ 86.32
Depreciation, depletion, amortization and accretion	\$ 33.96	\$ 24.47	\$ 23.40

(1) Excludes the impact of oil derivative instruments.

(2) For the year ended December 31, 2012, general and administrative excludes non-cash stock-based compensation expense of approximately \$25.5 million, or \$54.49 per boe. We did not have any stock-based compensation expense for the prior periods presented.

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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.

	Year Ended December 31,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
<b>Development wells:</b>						
Productive	14.0	9.5	3.0	1.6	6.0	3.0
Dry						
<b>Exploratory wells:</b>						
Productive	6.0	5.5			2.0	0.8
Dry						
<b>Total wells:</b>						
Productive	20.0	15.0	3.0	1.6	8.0	3.8
Dry						

The following table sets forth information at December 31, 2012 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	13.0	11.5		
Non-operated	16.0	8.0	1.0	0.3
<b>Total</b>	<b>29.0</b>	<b>19.5</b>	<b>1.0</b>	<b>0.3</b>

*Developed and Undeveloped Acreage*

The following table sets forth information as of December 31, 2012 relating to our leasehold acreage. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary. As of December 31, 2012, 12% of our acreage was held by production.

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Eagle Ford Shale Palmetto	1,280	612	18,948	9,058
Eagle Ford Shale Maverick	840	792	31,715	27,644
Eagle Ford Shale Marquis	360	360	57,077	56,716
Other	240	60	85,936	83,189
<b>Total</b>	<b>2,720</b>	<b>1,824</b>	<b>193,676</b>	<b>176,607</b>

As of December 31, 2012, we had leases representing 14,880 net acres (14,834 of which were in the Eagle Ford Shale) expiring in 2013, 2,578 net acres (2,576 of which were in the Eagle Ford Shale)

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expiring in 2014, and 40,948 net acres (all of which were in the Eagle Ford Shale) expiring in 2015. We anticipate that our current and future drilling plans will address the majority of our leases expiring in the Eagle Ford Shale in 2013. In addition, included in the 14,834 net acres expiring in 2013 in the Eagle Ford Shale is a single lease for approximately 5,600 net acres, and a single well drilled to any depth producing commercial quantities of oil and gas will hold the lease. Our 82,274 net acres in the Heath, Three Forks and Bakken Shales expire in 2013 but have an option to renew for another five years at \$10 per acre, which we anticipate exercising.

***Delivery Commitments***

As of December 31, 2012, we had no delivery commitments with respect to our production.

**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 72.0% to 84.5%.

***Marketing and Major Customers***

For the year ended December 31, 2012, purchases by three of our customers accounted for 63%, 18% and 16%, respectively, of our total sales 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, Penn Virginia Corporation and Magnum Hunter Resources Corporation. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than

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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 otherwise relating to protection of the environment or occupational health and safety. Numerous



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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 the current owner or operator of the site where the release occurred, past owners or operators at the

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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 May 4, 2012, the EPA published a draft UIC Program guidance for oil and natural gas hydraulic fracturing activities using diesel fuel. The guidance document is designed for use by employees of the EPA that draft the UIC permits and 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. The draft guidance underwent an extended public comment process, which concluded on August 23, 2012. The EPA is presently evaluating the public comments and subsequently likely will issue a final guidance document at a later date.

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. Furthermore, on April 17, 2012, the EPA published in the Federal Register a proposed rule establishing new air emission controls for oil and natural gas production and natural gas processing operations. The final rule became effective October 15, 2012, however, a number of the requirements did not take immediate effect. The final rule established a phase-in period to allow for the manufacture and distribution of required emissions reduction technology. The rule requires owners and operators to either flare volatile organic compound, or VOC, emissions or use emissions reduction technologies, or green completions, which allow the emissions to be recaptured and treated. On or after January 1, 2015, all newly fractured wells will be required to use green completions. Certain compressors, dehydrators, and other equipment must also comply with the final rule immediately or up to three years and 60 days after publication of the final rule, depending on the construction date and/or nature of the unit. Also, on May 4, 2012, the U.S. Department of Interior, or DOI, issued a draft 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 2013. 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.

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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 coalbed methane and shale gas operations to pretreat wastewater before transferring it to treatment facilities. Proposed rules are expected in 2013 for coalbed methane and 2014 for shale gas. 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.

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

***Air Emissions***

The federal Clean Air Act, as amended, or the CAA, and comparable state laws, regulate emissions of various air pollutants through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. In particular, on April 17, 2012, the EPA published in the Federal Register a proposed rule establishing new air emission controls for oil and natural gas production and natural gas processing operations. The final rule became effective October 15, 2012, however, a number of the requirements did not take immediate effect. The final rule established a phase-in period to allow for the manufacture and distribution of required emissions reduction technology. The rule requires owners and operators to either flare VOC emissions or use emissions reduction technologies, or green completions, which allow the emissions to be recaptured and treated. On or after January 1, 2015, all newly fractured wells will be required to use green completions. Also, on May 4, 2012, the DOI issued a draft 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 2013. 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. On

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October 30, 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA published a final rule expanding this 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. The EPA also adopted the motor vehicle rule, which became effective January 2011, and which limits emissions of GHGs from motor vehicles manufactured in model years 2012-2016. On August 28, 2012, the EPA and the Department of Transportation's National Highway Traffic Safety Administration, or NHTSA, issued a final rule expanding the motor vehicle rule to include passenger vehicles manufactured in model years 2017-2025. Finally, the EPA adopted a rule covering stationary sources, known as the tailoring rule, which became effective in January 2011, although it remains the subject of several pending lawsuits filed by industry groups. The tailoring rule establishes new GHG emissions thresholds that determine those stationary sources that must obtain permits under the Prevention of Significant Deterioration, or PSD, and Title V programs of the CAA. The permitting requirements of the PSD program apply to newly constructed or modified major sources. Obtaining a PSD permit requires a source to install best available control technology, or BACT, for those regulated pollutants that are emitted in certain quantities. Phase I of the tailoring rule, which became effective on January 2, 2011, requires projects already triggering PSD permitting that are also increasing GHG emissions by more than 75,000 tons per year to comply with BACT rules for their GHG emissions. Phase II of the tailoring rule, which became effective on July 1, 2011, requires preconstruction permits including BACT for new projects that emit 100,000 tons of GHG emissions per year or existing facilities that make major modifications increasing GHG emissions by more than 75,000 tons per year. Phase III of the tailoring rule, which is expected to go into effect in 2013, will seek to streamline the permitting process and permanently exclude smaller sources from the permitting process. Finally, on March 27, 2012, the EPA issued a proposed rule establishing carbon pollution standards for new fossil-fuel-fired electric utility generating units. The proposed rule underwent an extended public comment process, which concluded on June 25, 2012. The EPA is presently evaluating the public comments and is expected to issue a final rule at a later date. The EPA also had planned to implement GHG emissions standards for refineries in November 2012, although final action has yet to be taken.

In addition, both houses of Congress have actively considered legislation to reduce emissions of GHGs. One bill approved by the U.S. House of Representatives in June 2009, known as the American Clean Energy and Security Act of 2009, would have required an 80% reduction in emissions of GHGs from sources within the U.S. between 2012 and 2050, but it was not approved by the U.S. Senate in the 2009-2010 legislative session. The U.S. Congress is likely to continue to consider similar bills. Moreover, 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

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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 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

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

***Natural Gas Regulation***

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

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.



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***State Regulation***

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

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

**Employees**

We currently do not have any employees. Pursuant to our Services Agreement with SOG, SOG performs services for us, including the operation of our properties. Please read Note 9 "Related Party Transactions" in the notes to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

As of December 31, 2012, SOG had approximately 115 employees, including 9 engineers, 12 geoscientists and 7 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 a lease entered into by SOG covering approximately 27,500 square feet of office space in Houston, Texas at 1111 Bagby Street, Suite 1800, Houston, Texas 77002. SOG's lease expires in April 2023. SOG also maintains offices in Laredo and San Antonio, Texas.

**Legal Proceedings**

Although 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 currently a party to any material legal proceeding. In addition, we are not aware of any material legal or governmental proceedings against us or contemplated to be brought against us.

**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>.

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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.

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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. Moreover, the variability is likely to be higher for probable and possible reserve estimates. For example, if the prices used in our reserve report as of December 31, 2012 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 \$71.6 million, from approximately \$286.3 million to approximately \$214.7 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



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to do so, or if expected development is delayed, reduced or cancelled, the average decline rates will likely increase.

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

The cost of developing, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce as much oil, natural gas and NGLs as we had estimated. In addition, our use of 2D and 3D seismic data and visualization techniques to identify subsurface structures and hydrocarbon indicators do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures and requires greater pre-drilling expenditures than traditional drilling strategies. Furthermore, our development and production operations may be curtailed, delayed or canceled as a result of other factors, including:

high costs, shortages or delivery delays of rigs, equipment, labor or other services;

composition of sour gas, including sulfur and mercaptan content;

unexpected operational events and conditions;

reductions in oil, natural gas and NGL prices;

increases in severance taxes;

adverse weather conditions and natural disasters;

facility or equipment malfunctions and equipment failures or accidents, including acceleration of deterioration of our facilities and equipment due to the highly corrosive nature of sour gas;

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;

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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; 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

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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.



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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 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.

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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;

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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.

We currently have four commodity derivative contracts in place covering approximately 40% of our expected production during 2013. The contracts consist of two swaps and two put spreads, all covering crude oil production. Subsequent to December 31, 2012, we entered into two additional oil derivative contracts, both three-way costless collars, covering approximately 20% of our estimated 2014 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 realized and unrealized hedging gains or losses. 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.***

Economic uncertainty in the United States, Europe and Asia could create financial challenges if conditions do not improve. Standard & Poor's downgraded the U.S. credit rating to AA+ from its top rank of AAA and more recently has downgraded the credit ratings for several countries in Europe, which has increased the possibility of other credit-rating agency downgrades which could have a material adverse effect on the financial markets and economic conditions in the United States and throughout the world. Our ability to access capital may be restricted at a time when we would like, or need, to raise capital. If our cash flow from operations is less than anticipated and our access to capital is restricted, 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

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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. In particular, take away capacity in the Eagle Ford Shale has become a significant challenge for some operators, including in our Palmetto area. 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.

***Availability of adequate gathering systems and transportation take-away capacity may hinder our access to suitable oil, natural gas and NGL markets or delay our production.***

Our ability to bring oil, natural gas and NGL production to market depends on a number of factors including the availability and proximity of pipelines and processing facilities. The recent dramatic growth in production in the Eagle Ford Shale has limited the availability of transportation take-away capacity for these products in certain parts of this trend, including in our Palmetto area. If we or the operators on our acreage are unable to obtain adequate amounts of take-away capacity to meet our growing production levels, we may have to delay initial production or shut in our wells awaiting a pipeline connection or capacity or sell our production at significantly lower prices than those quoted on NYMEX or than we currently project, which could adversely affect our business, financial condition and results of operations.

***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.

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***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. Our 82,274 net acres in the Heath, Three Forks and Bakken Shales expire in 2013 but have an option to renew for another five years at \$10 per acre, which we anticipate exercising. As of December 31, 2012, we had leases representing 14,880 net acres (14,834 of which were in the Eagle Ford Shale) expiring in 2013, 2,578 net acres (2,576 of which were in the Eagle Ford Shale) expiring in 2014, and 40,948 net acres (all of which were in the Eagle Ford Shale) expiring in 2015. While we anticipate that our current and future drilling plans will address the majority of our leases expiring in the Eagle Ford Shale in 2013, 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.

***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

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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 May 4, 2012, the EPA published a draft UIC Program guidance for oil and natural gas hydraulic fracturing activities using diesel fuel. The guidance document is designed for use by employees of the EPA that draft the UIC permits and 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. The draft guidance underwent an extended public comment process, which concluded on August 23, 2012. The EPA is presently evaluating the public comments and subsequently likely will issue a final guidance document at a later date.

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 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 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. Finally, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board released a report on August 11, 2011, proposing recommendations to reduce the potential environmental impacts from shale gas production.

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. Furthermore, on April 17, 2012, the EPA published in the Federal Register a proposed rule establishing new air emission controls for oil and natural gas production and natural gas processing operations. The final rule became effective October 15, 2012, however, a number of the requirements did not take immediate effect. The final rule established a phase-in period to allow for the manufacture and distribution of required emissions reduction technology. The rule requires owners and operators to either flare VOC emissions or use emissions reduction technologies, or green completions, which allow the emissions to be recaptured and treated. On or after January 1, 2015, all newly fractured wells will be required to use green completions. Certain compressors, dehydrators, and other equipment must

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also comply with the final rule immediately or up to three years and 60 days after publication of the final rule, depending on the construction date and/or nature of the unit. Also, on May 4, 2012, the DOI issued a draft 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 2013. 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.

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 coalbed methane and shale gas operations to pretreat wastewater before transferring it to treatment facilities. Proposed rules are expected in 2013 for coalbed methane and 2014 for shale gas. 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.

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.

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***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. 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 2013. 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.



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

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

mistaken assumptions about estimated proved reserves, future production, revenues, capital expenditures, operating expenses and costs, including synergies, timing of expected development and the potential for expiration of underlying leaseholds;

an inability to successfully integrate the assets or businesses we acquire;

a decrease in our liquidity by using a significant portion of our cash and cash equivalents to finance acquisitions;

a significant increase in our interest expense or financial leverage if we incur debt to finance acquisitions;

the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which any indemnity we receive is inadequate;

the diversion of management's attention from other business concerns;

mistaken assumptions about the overall cost of equity or debt;

an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;

facts and circumstances that could give rise to significant cash and certain non-cash charges; and

customer or key employee losses at the acquired businesses.

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

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

***We 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



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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

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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. 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

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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.

***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

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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. On October 30, 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA published a final rule expanding this 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. The EPA also adopted the motor vehicle rule, which became effective January 2011, and which limits emissions of GHGs from motor vehicles manufactured in model years 2012-2016. On August 28, 2012, the EPA and the NHTSA issued a final rule expanding the motor vehicle rule to include passenger vehicles manufactured in model years 2017-2025. Finally, the EPA adopted a rule covering stationary sources, known as the tailoring rule, which became effective in January 2011, although it remains the subject of several pending lawsuits filed by industry groups. The tailoring rule establishes new GHG emissions thresholds that determine those stationary sources that must obtain permits under the PSD and Title V programs of the CAA. The permitting requirements of the PSD program apply to newly constructed or modified major sources. Obtaining a PSD permit requires a source to install BACT for those regulated pollutants that are emitted in certain quantities. Phase I of the tailoring rule, which became effective on January 2, 2011, requires projects already triggering PSD permitting that are also increasing GHG emissions by more than 75,000 tons per year to comply with BACT rules for their GHG emissions. Phase II of the tailoring rule, which became effective on July 1, 2011, requires preconstruction permits including BACT for new projects that emit 100,000 tons of GHG emissions per year or existing facilities that make major modifications increasing GHG emissions by more than 75,000 tons per year. Phase III of the tailoring rule, which is expected to go into effect in 2013, will seek to streamline the permitting process and permanently exclude smaller sources from the permitting process. Finally, on March 27, 2012, the EPA issued a proposed rule establishing carbon pollution standards for new fossil-fuel-fired electric utility generating units. The proposed rule underwent an extended public comment process, which concluded on June 25, 2012. The EPA is presently evaluating the public comments and is expected to issue a final rule at a

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later date. The EPA also had planned to implement GHG emissions standards for refineries in November 2012, although final action has yet to be taken.

In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act, or the ACES Act, that, among other things, would have established a cap-and-trade system to regulate GHG emissions and would have required an 80% reduction in GHG emissions from sources within the United States between 2012 and 2050. The ACES Act did not pass the Senate, however, and so was not enacted by the 111th Congress. The United States Congress is likely to consider again a climate change bill in the future. In addition, 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

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experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time.

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

***Federal legislation regarding derivatives could have an adverse effect on our ability and cost of entering into derivative transactions.***

On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Reform Act, which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new legislation required the Commodities Futures Trading Commission, or CFTC, and the SEC to promulgate rules implementing the new legislation within 360 days from the date of enactment. These rules have been adopted and those rules which have not been vacated and are not yet effective are scheduled to take effect on April 10, 2013, May 1, 2013 or July 1, 2013, after giving effect to an extension of certain reporting requirements.

The CFTC issued a final rule providing for position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. This rule was vacated and remanded to the CFTC for further proceedings by order of the United States District Court for the District of Columbia on September 28, 2012. The CFTC has appealed this ruling and, if it loses such appeal, the CFTC may issue another position limit rule after conducting such further proceedings. Under the stricken rule, certain bona fide hedging transactions or positions are exempt from the position limits and the Company expects to satisfy the conditions for such exemptions. The CFTC has issued final rules, which have not been vacated, further defining "swap," "swap dealer" and "major swap participant" and specifying the reporting and other requirements for "non-financial entities" to elect the exception to the clearing requirement under the Commodity Exchange Act, or the CEA. The Company qualifies as a non-financial entity under the CEA and intends to comply with the reporting and other requirements of the exception and utilize the exception. Although the rules will not impose clearing requirements on the Company, they will impose additional reporting and recordkeeping requirements on the Company and clearing, capital, margin and reporting and recordkeeping on swap dealers and major swap participants and will also require certain potential swap counterparties of the Company to conduct their swap activities through affiliates which may be less creditworthy than existing



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potential swap counterparties. This, and, if the position limit rule is reinstated or a new position limit rule is adopted, the position limit rule 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 existing derivative contracts, and increase our potential exposure to less creditworthy counterparties. If we reduce our use of derivatives or commodity prices decline as a result of the legislation and regulations, our results of operations may become more volatile and cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures, our results of operations, or our cash flows.

***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 2013 for coalbed methane and 2014 for shale gas. 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. 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.

***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

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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.

***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.***

The President's proposed budget for fiscal year 2013 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

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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 and ongoing 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 and ongoing relationships, including:

labor, tax, employee benefit, indemnification and other matters arising under agreements with SOG;

employee recruiting and retention; and

business opportunities that may be attractive to both members of the Sanchez Group and us.

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;

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

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



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

Certain services required by us for the operation of our business, including general and administrative services, geological, geophysical and reserve engineering, lease and land administration, marketing, accounting, operational services, information technology services, compliance, insurance maintenance and management of outside professionals, are provided by SOG pursuant to 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 2013 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 9 "Related Party Transactions" in the notes to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" of this Annual Report on Form 10-K. This database includes the 2D and 3D seismic data used for our exploration and development projects as well as the well logs, LAS files, scanned well documents and other well documents and software that are necessary for our daily operations. This information is critical for the operation and expansion of our business. Under certain circumstances, including if SOG provides at least 180 days' advance written notice of its desire to terminate the Services Agreement, the license agreement will terminate and we will lose our rights to this technological database unless members of the Sanchez Group permit us to retain some or all of these rights, which they may decline to do in their sole discretion. In such event, we are unlikely to be able to obtain rights to similar information under substantially similar commercial terms or to continue our business operations as proposed and our liquidity, business, financial condition and results of operations will be materially and adversely affected and it could delay or prevent an acquisition of us.

***Our 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;

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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 17% of our outstanding common stock. These shares are restricted securities, as defined in Rule 144 under the Securities Act, but 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.



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**Risks Related to the Hess Acquisition**

*We may not be able to consummate the transactions contemplated by the purchase and sale agreement for the acquisition of certain assets from Hess Corporation.*

On March 18, 2013, we entered into the purchase and sale agreement for the acquisition of certain assets from Hess. The consummation of the Hess acquisition is subject to certain closing conditions, including conditions that must be met by Hess and which are beyond our control. In addition, under certain circumstances, we or Hess are able to terminate the purchase and sale agreement. Furthermore, although it is not a condition to closing, it may be necessary for us to obtain additional financing to fund a portion of purchase price for the Hess acquisition at closing, which we may not be able to satisfactorily obtain. There can be no assurances that the Hess acquisition will be consummated in the anticipated timeframe or at all.

If the Hess acquisition is not consummated under certain circumstances, we may be required to forfeit a deposit under the purchase and sale agreement. Furthermore, our stock price could be negatively impacted if we fail to complete the Hess acquisition.

*The Hess acquisition involves risks associated with acquisitions and integrating acquired assets, including the potential exposure to significant liabilities, and the intended benefits of the Hess acquisition may not be realized.*

The Hess acquisition involves 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 Hess acquisition;

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 Hess acquisition may not perform as well as we anticipate; and

unexpected costs, delays and challenges may arise in integrating the assets acquired in the Hess acquisition into our existing operations.

Even if we successfully integrate the assets acquired in the Hess acquisition 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 Hess acquisition, our business, results of operations and financial condition may be adversely affected.

**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**

Although 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 currently a party to any material legal proceeding. In addition, we are not aware of any material legal or governmental proceedings against us or contemplated to be brought against us.

**Item 4. Mine Safety Disclosures**



Not applicable.

Table of Contents**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." Our shares have been traded on the NYSE since December 14, 2011, and therefore, we have not set forth quarterly information with respect to the high and low prices for our common stock prior to 2012. The following table sets forth the reported high and low closing prices of our common stock for the periods indicated:

	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 15, 2013, the last sale price of our common stock, as reported on the NYSE, was \$19.40 per share.

*Holdings.* The number of shareholders of record of our common stock was approximately 57 on March 15, 2013, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or a bank.

*Dividends.* 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, 2012 regarding the Sanchez Energy Corporation Amended and 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.

	(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))
<b>Plan Category:</b>			
Equity Compensation Plans Approved by Stockholders		N/A	4,187,600(1)
Equity Compensation Plans Not Approved by Stockholders	N/A	N/A	N/A
<b>Total</b>			4,187,600

(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.

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*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, 2012.

**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, 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, 2012. The selected financial data as of December 31, 2012, 2011, 2010 and 2009 and for the years ended December 31, 2012, 2011, 2010, 2009 and 2008 are derived from our audited historical financial statements. The selected financial data as of December 31, 2008 is derived from the unaudited financial records of SEP I.

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.

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.

	<b>Year Ended December 31,</b>				
	<b>2012</b>	<b>2011</b>	<b>2010</b>	<b>2009</b>	<b>2008</b>
	<b>(in thousands, except per share amounts)</b>				
<b>REVENUES:</b>					
Oil sales	\$ 42,377	\$ 13,905	\$ 4,404	\$ 241	\$
Natural gas liquids sales	15	22			
Natural gas sales	766	589	149		
<b>Total revenues</b>	<b>43,158</b>	<b>14,516</b>	<b>4,553</b>	<b>241</b>	
<b>COSTS AND EXPENSES:</b>					
Oil and natural gas production expenses	3,401	1,628	391	9	
Production and ad valorem taxes, net	2,124	830	214	11	
Depreciation, depletion, amortization and accretion(1)	15,922	4,252	1,430	1,029	
Gain on sale of oil and natural gas properties				(2,686)	
General and administrative(2)	37,239	5,368	5,276	1,833	1,247
<b>Total operating costs and expenses</b>	<b>58,686</b>	<b>12,078</b>	<b>7,311</b>	<b>196</b>	<b>1,247</b>
Operating income (loss)	(15,528)	2,438	(2,758)	45	(1,247)
Other income (expense):					
Interest and other income	74	10			
Interest expense	(99)				
Unrealized losses on derivatives	(742)	(480)			
<b>Net income (loss)</b>	<b>(16,295)</b>	<b>1,968</b>	<b>(2,758)</b>	<b>45</b>	<b>(1,247)</b>
Less:					
Preferred stock dividends	(2,112)				
<b>Net income (loss) attributable to common stockholders</b>	<b>\$ (18,407)</b>	<b>\$ 1,968</b>	<b>\$ (2,758)</b>	<b>\$ 45</b>	<b>\$ (1,247)</b>
Net income (loss) per common share basic and diluted	\$ (0.56)	\$ 0.09	\$ (0.12)	\$	\$ (0.06)
Weighted average number of shares used to calculate net income (loss) attributable to common stockholders basic and diluted(3)(4)	33,000	22,479	22,091	22,091	22,091

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(1)

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

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- (2) Includes stock-based compensation expense of \$25.5 million for the year ended December 31, 2012.
- (3) Weighted average shares used to compute earnings (loss) per share for the years ended December 31, 2010, 2009 and 2008 represent those share 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.
- (4) 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 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.

	<b>As of December 31,</b>				
	<b>2012</b>	<b>2011(1)</b>	<b>2010</b>	<b>2009</b>	<b>2008</b>
	<b>(in thousands)</b>				
<b>Balance Sheet Data:</b>					
Working capital (deficit)	\$ 15,671	\$ 63,890	\$ (1,818)	\$ 59	\$ (65)
Total assets	\$ 426,574	\$ 217,356	\$ 26,765	\$ 13,275	\$ 14,262
Total parent net investment/stockholders' equity	\$ 366,743	\$ 215,141	\$ 22,162	\$ 13,218	\$ 14,197

- (1) On December 19, 2011 we acquired 100% of the limited liability company interests in Marquis LLC, which are incl