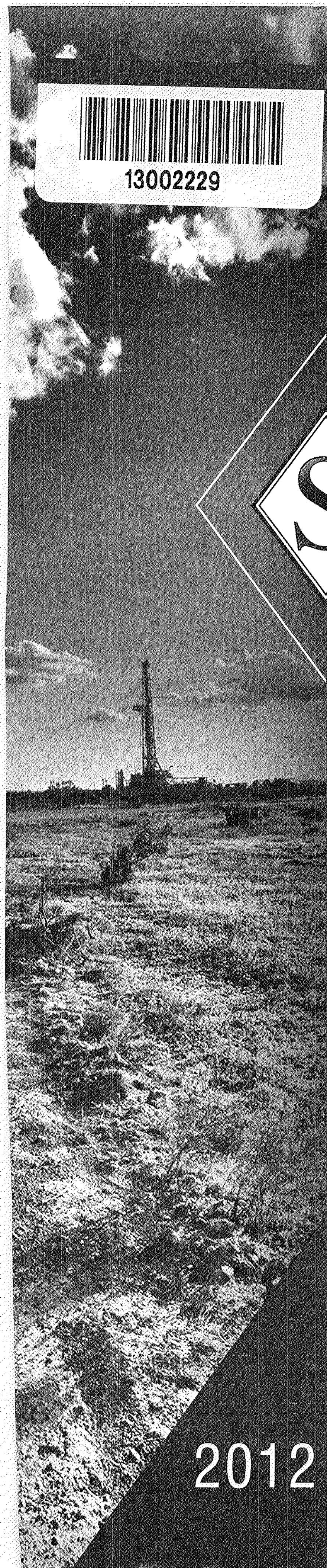
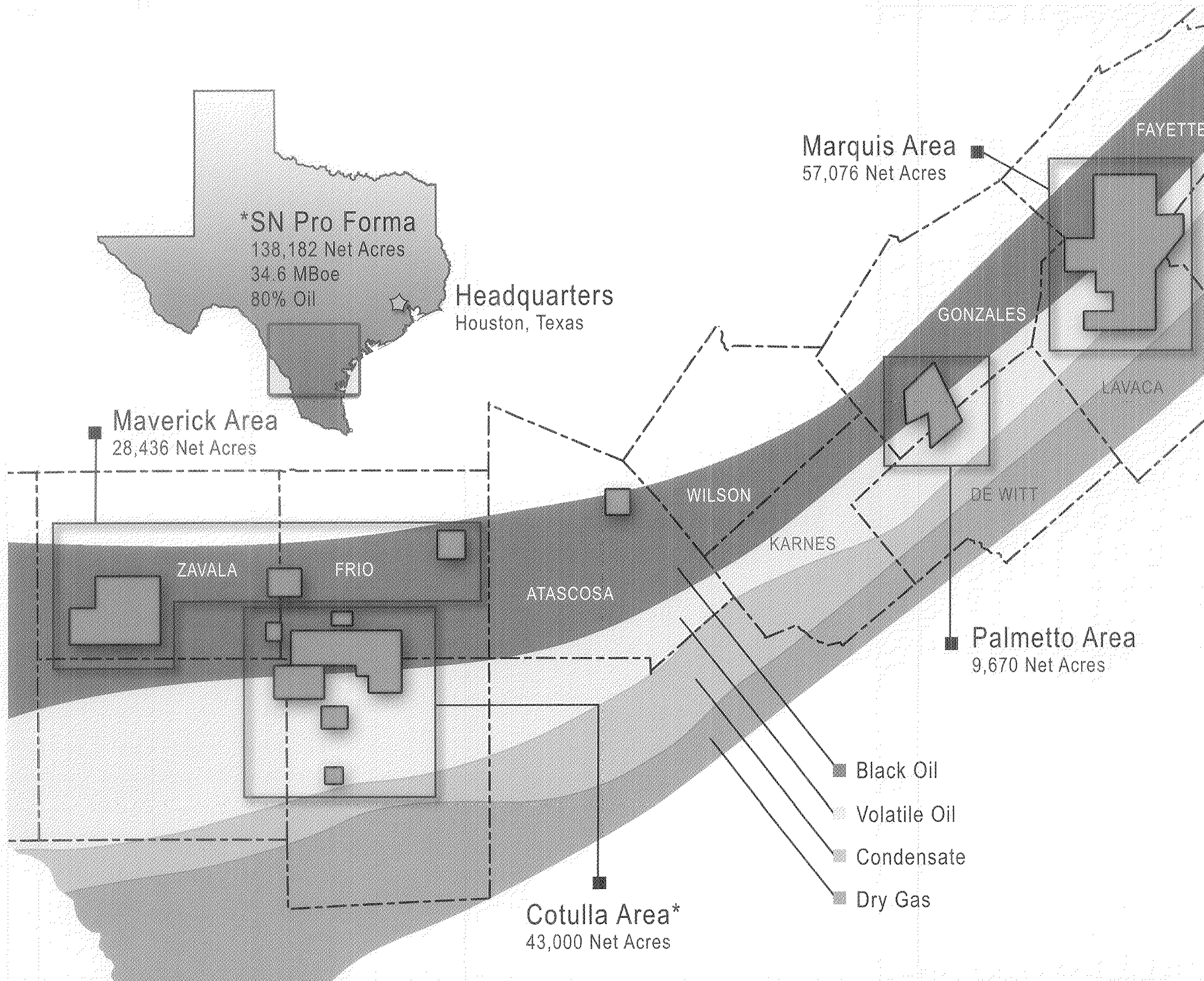


# SANCHEZ ENERGY CORPORATION

On The Move!

2012 Annual Report

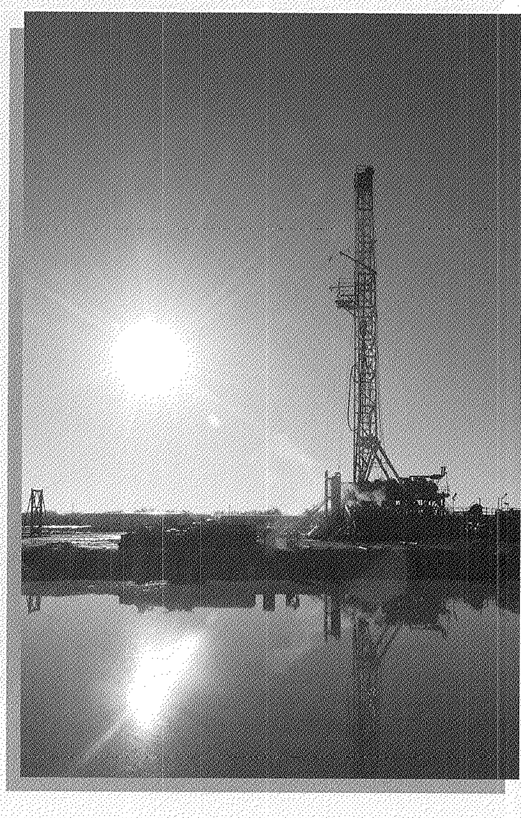



## CORPORATE PROFILE

Sanchez Energy Corporation (NYSE: SN) is a Houston, Texas based growth-oriented independent exploration and production company currently focused on the Eagle Ford Shale trend of South Texas. The Company has approximately 95,000 net acres targeting the liquids-rich Eagle Ford Shale, Pearsall Shale, Austin Chalk, and Buda Limestone, prior to the pending Cotulla area acquisition, which is scheduled to close during the second quarter of 2013.

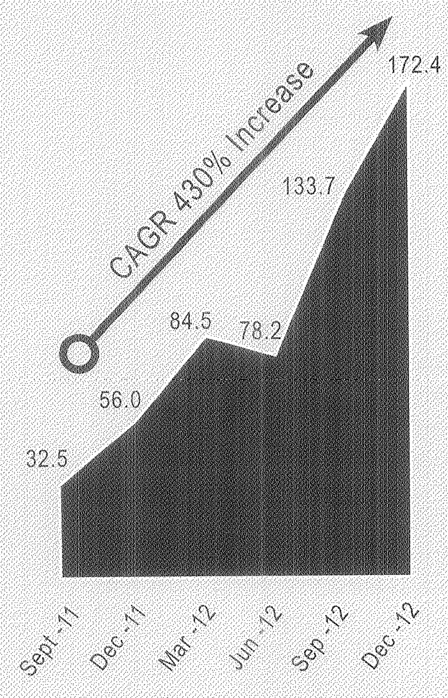
# TO OUR FELLOW SHAREHOLDERS:

It is often said that past performance doesn't ensure future success, but I am pleased to report that in the case of Sanchez Energy Corporation, our decades of collective experience operating in the prolific onshore basins of South Texas has produced what I believe are market-leading results in 2012. As a new public company that had just begun trading following our 2011 initial public offering, we set what some may have viewed as aggressive operational targets for our full-year 2012 performance. In my experience, beating market expectations requires setting aggressive goals, which is one of the benchmarks against which energy companies are measured. We said last year that we would achieve certain milestones, which we did, thanks to the tireless efforts of our entire team. Sanchez Energy Corporation performed well in 2012, and we are positioned to accelerate our operational activity in 2013, which should be another exciting year for our employees and our shareholders.

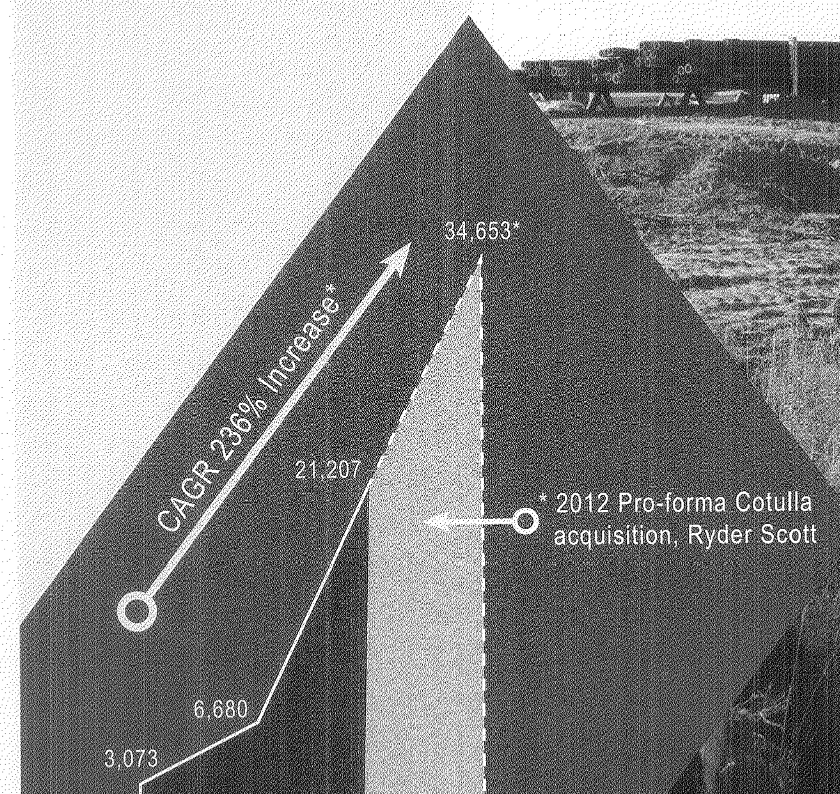


## OUR CORE FOCUS IS INCREASING SHAREHOLDER VALUE

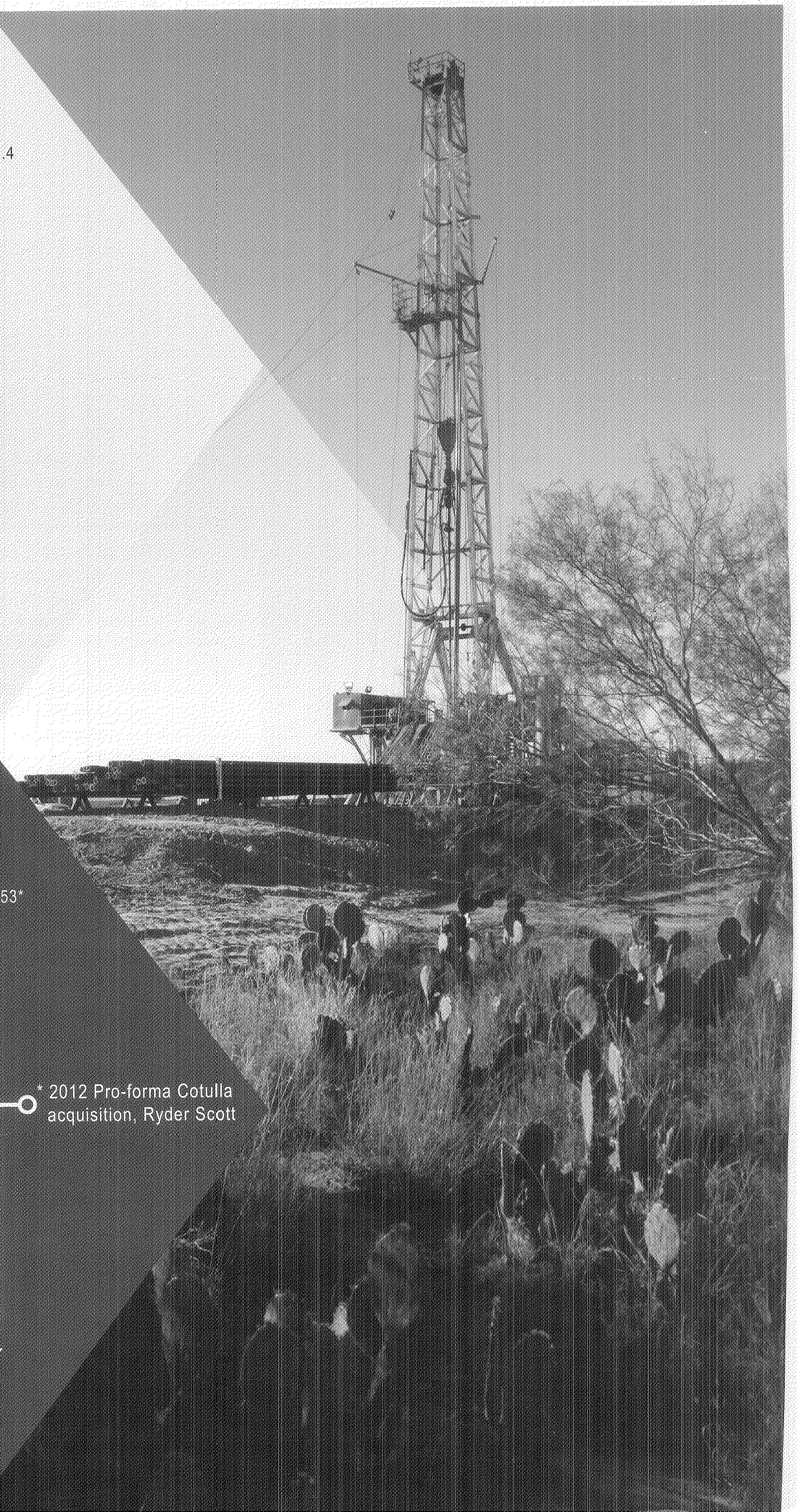
The oil and gas business can be a vexing industry because every company is subject to what may at times seem to be random fluctuations in commodity prices. Given this variability, successful energy companies like Sanchez Energy focus on controlling what we can control, which in our case means building our resource base and then drilling our inventory to grow production and reserves as efficiently as possible. The Eagle Ford Shale has been ranked by energy research firm Wood Mackenzie as the largest single oil and gas development in the world based on capital expenditures, and we have amassed one of the most concentrated Eagle Ford Shale acreage positions in the industry, certainly when compared to other similarly-sized companies, and are always assessing additional acreage to enhance our Eagle Ford drilling inventory. For the moment, we have built our acreage position and resource base into the critical mass necessary to accelerate our development program, which in turn will enhance cash flows and enable us to continue increasing our reserves and production. These are the fundamental ways in which Sanchez




**Quarterly Production**
(MBoe)




**Proved Reserves**
(MBoe)



Energy will increase shareholder value, and I can assure you that our entire company is focused each and every day on operating safely and efficiently in order to deliver higher production and larger booked reserves. As a result, accelerating the drilling and development of our reserves is our priority for 2013.

An investment in Sanchez Energy represents a vote of confidence in our vision, our strategy, our personnel, and our integrity.

## CURRENT INVENTORY PROVIDES GROWTH CATALYSTS FOR YEARS TO COME

95,000 acres is a substantial amount of land when one considers that within the Eagle Ford Shale trend we began drilling on 640 acre sections and now believe that we may ultimately down-space our wells to 40 to 60 acre spacing. The Eagle Ford is a tight carbonate siltstone, which means that it is geologically a tight formation that requires advanced technology to produce reserves economically. Due to these geological characteristics, we believe we have the advantage of being able to down-space our wells, which in turn may increase the ultimate recovery of hydrocarbons from our acreage position. This is important because, as I wrote last year, Sanchez Energy's continuing success will be based on our efficient development drilling as opposed to continuing to increase our total land inventory. Our strategy depends upon managing our drilling program based upon what we can plan and execute each year to deliver established production and reserves growth targets, and I believe we have the required inventory and technical expertise to deploy our capital over time in a way that will deliver consistent production and reserve growth.

## 2012 IN REVIEW

I want to begin my 2012 review by highlighting our operational achievements. Our drilling activities were weighted to the second half of the year. We spud 34 gross wells, 26.5 net, brought 20 wells online with 14 wells either drilling or waiting on completion at year end. Our year-end exit production rate was 4,500 barrels of oil equivalent per day ("BOE/d"), a 233% increase over 2011 – a year in which we had exited with 1,350 BOE/d. What is more significant, however, is the fact that we had approximately 750 BOE/d shut-in at year-end due to facility constraints. Given the ambitious goals we set for ourselves, some questioned whether we would be able to achieve an exit rate within our guidance of 4,000-5,000 BOE/d but that was the target we set, and our operational teams delivered. I cannot emphasize enough how important I believe this is to the future of our company because I can assure investors we are striving every day to deliver what we say we will do, which is what I believe investors expect from us.

Our 2012 drilling program allowed us to increase our booked reserves by 216% to 21.2 million BOE, and I have every expectation that we will be able to deliver solid growth in proved reserves again this year. One statistic I would like our shareholders to keep in mind is that our production and reserves growth in 2012 was based upon our drilling and completing 20 producing wells, with 10 wells awaiting completion at the end of 2012. Our capital allocation plan for 2013 calls for us to drill 46 gross (33.5 net) wells next year, a 200% increase over the initial capital plan in 2012.

Sanchez Energy's internal estimate for our total year-end 2012 resource base is approximately 345 million Boe in the Eagle Ford, based upon a drilling inventory of approximately 1,200 net locations at 80 acre spacing. If 2012 were to become the "baseline" year in terms of number of wells drilled and completed, this gives us a reserve life of 60 years.

## FINANCIAL FLEXIBILITY

Our reserve and production growth during 2012 has set the stage for steadily increasing financial flexibility for us. Early in 2013, we announced an increase in our borrowing capacity to $95 million all of which is unused at the time of this letter. We expect our debt capacity to steadily grow throughout 2013 as a result of our planned drilling program which, combined with our increased production driven cash flows should allow us to fund our planned capital program while still maintaining a conservative leverage position.

## 2013 – OUR MANDATE IS CONTINUED GROWTH

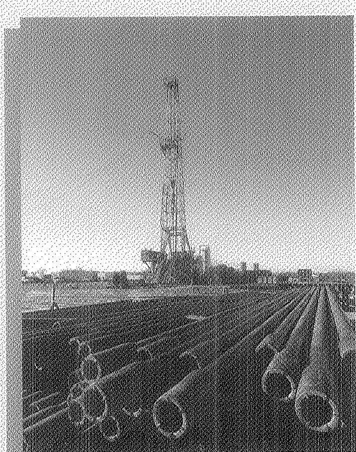
Although Sanchez Energy is a young public company, we have decades of experience in the oil and gas business. Since we achieved in 2012 what we set out to do, I will outline our operational plans for 2013, which will be a year in which Sanchez

**Our 2013 drilling program and capital commitment position Sanchez Energy to deliver triple-digit percentage growth in production and reserves again this year.**

Energy accelerates our development to solidify a track record of positive growth in production and reserves as a public company. Over the years as our investors follow our story, we will demonstrate time and again our commitment to increasing shareholder value by doing what Sanchez Energy does best, drilling oil wells and managing our reserves inventory.

## WHAT'S IN STORE FOR 2013

Our capital expenditure program in 2013 consists of a total of approximately $350 million, over 90% of which is allocated to drilling and completing wells. This capital budget should enable us to drill and complete 46 gross (33.5 net) wells this year, which in turn should enable us to hit our projected exit production rate of 8,500-9,500 BOE/d, a 100% increase over 2012.



How will we double our production exit rate in 2013 compared to 2012? By continuing to drive efficiencies on a well-by-well basis, using pad drilling to reduce overall drilling times and improving our capital efficiency, increasing drilling activity in our Palmetto and Marquis areas, and drilling tighter density wells across our entire acreage position.

Once again, while these goals are ambitious, they provide the opportunity to highlight the competitive advantage we have - Sanchez Energy's operational teams. From the perspective of operations, leading this growth is Joseph DeDominic, our Chief Operating Officer. Joe brings significant, real-world experience to the Company. This experience includes driving organizational growth and process refinement while increasing production and reserves at a highly aggressive pace. Our operational teams are simply the best in the business and demonstrate this by delivering what I consider to be remarkable results weighted toward the latter half of 2012. We expect that they will do it again this year.

## FINAL THOUGHTS

Our 2013 drilling program and capital commitment position Sanchez Energy to deliver triple-digit percentage growth in production and reserves again this year. This in turn will steadily increase our cash flow and will demonstrate the repeatability of our operational program in the Eagle Ford. I know how important it is for the market and our investors to see tangible results over time, and I have every confidence we will again deliver on our targets in 2013. While aggressive, our 2013 objectives are achievable when one considers the deep expertise in Texas of Sanchez Energy's team of operational and technical personnel.

On March 18, 2013 we announced a significant, planned acquisition of oil and natural gas properties in the Eagle Ford Trend. This planned acquisition, which we expect to close late in the second quarter, has the potential to increase our proved reserves by over 60% and more than double our daily production volumes based upon the March 1, 2013 effective date. We believe this will be a very transforming transaction for Sanchez Energy.

An investment in Sanchez Energy represents a vote of confidence in our vision, our strategy, our personnel, and our integrity. I believe 2013 will be another watershed year in the history of our company. I am privileged to lead the Sanchez Energy team in delivering results year over year, which should enhance shareholder value and confirm the confidence you place in us with your capital support.

Antonio R. Sanchez, III
Chairman, President and
Chief Executive Officer
March 29, 2013

# 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**<br>(State or other jurisdiction of incorporation or organization) | **45-3090102**<br>(I.R.S. Employer Identification No.) |
| **1111 Bagby Street, Suite 1800**<br>**Houston, Texas**<br>(Address of principal executive offices) | **77002**<br>(Zip Code) |

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

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

| (Title of Class) | (Name of Exchange) |
|---|---|
| Common Stock, par value $0.01 per share | New York Stock Exchange |

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

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

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

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

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

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

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

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 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.

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

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

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

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

**SANCHEZ ENERGY CORPORATION**
**FORM 10-K**
**FOR THE YEAR ENDED DECEMBER 31, 2012**

**Table of Contents**

## 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;

- 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.

# PART I

## Item 1. *Business*

### Overview

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:

| | | Identified Drilling Locations(1) | | 2013 Capital Expenditure Budget | | | |
|---|---|---|---|---|---|---|---|
| | Net Acreage | Gross | Net | Gross Wells | Net Wells | Drilling Capex (in millions) | Estimated Net Proved Reserves(2) (mmboe) |
| 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) 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.

**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

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.

- *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 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 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.

*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 |
|---|---|
| Reserve Data(1): | |
| Estimated proved reserves: | |
| Oil (mbo) | 18,266 |
| Natural gas liquids (mbbl) | 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 (mbbl) | 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 (mbbl) | 211 |
| Natural gas (mmcf) | 13,355 |
| Total estimated proved undeveloped reserves (mboe)(2) | 17,491 |
| Standardized Measure (in millions)(1)(3) | $286.3 |

(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

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.

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

| | 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)** |
| **Project Area** | | | | | | |
| 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."

***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):

| | Reserves | | |
|---|---|---|---|
| | **Proved** | **Probable** | **Possible** |
| 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.

*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 |
|---|---|---|---|
| **Production:** | | | |
| **Oil—mbo** | | | |
| Palmetto | 262.7 | 132.2 | 43.4 |
| Maverick | 87.8 | 13.7 | 12.4 |
| Marquis | 67.4 | — | — |
| Other | — | — | — |
| Total | 417.9 | 145.9 | 55.8 |
| **Natural gas liquids—mbbl** | | | |
| Palmetto | 0.6 | 0.5 | — |
| Maverick | 0.1 | — | — |
| Marquis | — | — | — |
| Other | — | — | — |
| Total | 0.7 | 0.5 | — |
| **Natural gas—mmcf** | | | |
| Palmetto | 226.7 | 104.5 | 31.9 |
| Maverick | — | — | — |
| Marquis | — | — | — |
| Other | 74.5 | 59.6 | — |
| Total | 301.2 | 164.1 | 31.9 |
| **Net production volumes:** | | | |
| Total oil equivalent (mboe) | 468.8 | 173.7 | 61.1 |
| Average daily production (boe/d) | 1,280.8 | 475.9 | 167.4 |
| **Average Sales Price:** | | | |
| 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 |
| **Average unit costs per boe:** | | | |
| 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.

### *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 |
| **Development wells:** | | | | | | |
| Productive | 14.0 | 9.5 | 3.0 | 1.6 | 6.0 | 3.0 |
| Dry | — | — | — | — | — | — |
| **Exploratory wells:** | | | | | | |
| Productive | 6.0 | 5.5 | — | — | 2.0 | 0.8 |
| Dry | — | — | — | — | — | — |
| **Total wells:** | | | | | | |
| 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 |
| Total | 29.0 | 19.5 | 1.0 | 0.3 |

### *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 |
| Total | 2,720 | 1,824 | 193,676 | 176,607 |

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. 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 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 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 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.

***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 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.

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

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 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 affect other companies in the oil and natural gas industry with similar types, quantities and locations of production.

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

***Drilling and Production***

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

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

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the 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.

*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.

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

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

## Item 1A. *Risk Factors*

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

### Risks Related to Our Business

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

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

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

Numerous uncertainties are inherent in estimating quantities of oil, natural gas and NGL reserves and future production. It is not possible to measure underground accumulations of oil, natural gas and NGLs in an exact way. Oil, natural gas and NGL reserve engineering is complex, requiring subjective estimates of underground accumulations of oil, natural gas and NGLs and assumptions concerning future oil, natural gas and NGL prices, future production levels and operating and development costs.

In estimating our level of oil, natural gas and NGL reserves, we and our independent reserve engineers make certain assumptions that may prove to be incorrect, including assumptions relating to:

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

If these assumptions prove to be incorrect, our estimates of our reserves, the economically recoverable quantities of oil, natural gas and NGLs attributable to any particular group of properties, the classifications of reserves based on risk of recovery and our estimates of the future net cash flows from our estimated reserves could change significantly. 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 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;
- 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 changes in federal and state law, as well as proposed legislative changes, could significantly restrict the use of hydraulic fracturing. Such laws could make it more difficult or costly for us to perform fracturing to stimulate production from dense subsurface rock formations and, in the event of local prohibitions against commercial production of natural gas, may preclude our ability to drill wells. In addition, such laws could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. If hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA or other federal agencies, our fracturing activities could become subject to additional permitting requirements and result in permitting delays, financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements, as well as potential increases in costs. Please read "—Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays" and "Item 1. Business—Environmental Matters and Regulation—Water and Other Water Discharges and Spills."

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

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

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

Our cash on hand, cash flows from operations, ability to borrow and access to capital are subject to a number of variables, including:

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

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

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

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

- domestic and foreign supply of and demand for oil, natural gas and NGLs;
- weather conditions and the occurrence of natural disasters;
- overall domestic and global economic conditions;
- political and economic conditions in oil, natural gas and NGL producing countries globally, including terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war;
- actions of the Organization of Petroleum Exporting Countries, or OPEC, and other state-controlled oil companies relating to oil price and production controls;
- the effect of increasing liquefied natural gas and exports from the United States;
- the impact of the U.S. dollar exchange rates on oil, natural gas and NGL prices;
- technological advances affecting energy supply and energy consumption;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the proximity, capacity, cost and availability of oil, natural gas and NGL pipelines and other transportation facilities;
- the availability of refining capacity; and
- the price and availability of alternative fuels.

In the past, oil, natural gas and NGL prices have been extremely volatile, and we expect this volatility to continue. Such volatility may affect the amount of our net estimated proved reserves and will affect the standardized measure of discounted future net cash flows of our net estimated proved reserves.

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

Our revenue, profitability and cash flow depend upon the prices of and demand for oil, natural gas and NGL reserves, and a drop in prices can significantly affect our financial results and impede our growth. In particular, declines in commodity prices will:

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

- reduce the value and quantities of our reserves, because declines in oil, natural gas and NGL prices would reduce the amount of oil, natural gas and NGLs that we can economically produce;
- reduce the amount of cash flow available for capital expenditures; and
- limit our ability to borrow money or raise additional capital.

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

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

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 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.

***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 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 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.

***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.

***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 depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial, technical or personnel resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These larger companies may have a greater ability to continue development activities during periods of low oil, NGL and natural gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Furthermore, we may not be able to aggregate sufficient quantities of production to compete with larger companies that are able to sell greater volumes of production to intermediaries, thereby reducing the realized prices attributable to our production. Any inability to compete effectively with larger companies could have a material adverse impact on our business, financial condition and results of operations.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

On April 2, 2007, the U.S. Supreme Court ruled, in Massachusetts, et al. v. EPA, that the CAA definition of "pollutant" includes carbon dioxide and other GHGs and, therefore, the EPA has the authority to regulate carbon dioxide emissions from automobiles. Thereafter, on December 15, 2009, the EPA published its findings that GHG emissions present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. 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 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 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 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 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 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.

***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;

- 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.

**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.

## 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.

*Holders.* 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)) |
|---|---|---|---|
| **Plan Category:** | | | |
| 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 |
| **Total** | — | — | 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.

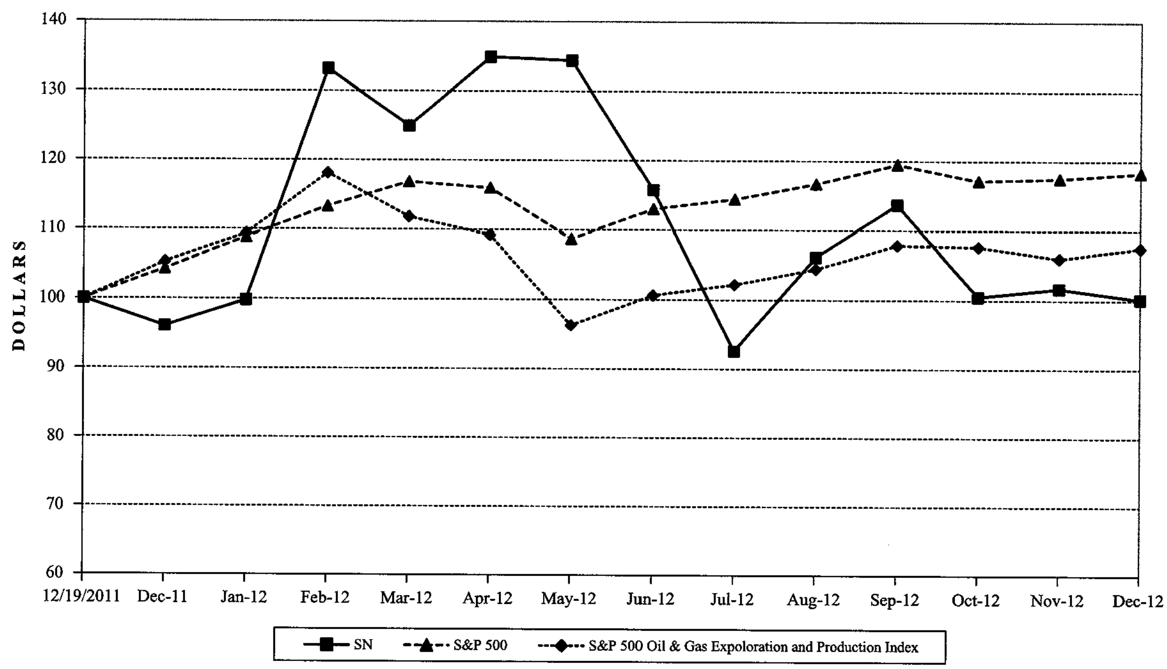
*Recent Sales of Unregistered Securities.* All sales of unregistered securities within the last fiscal year have been previously reported in our Quarterly Reports on Form 10-Q and/or Current Reports on Form 8-K.

*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.*

## 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.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | 2009 | 2008 |
| | (in thousands, except per share amounts) | | | | |
| **REVENUES:** | | | | | |
| Oil sales | $ 42,377 | $13,905 | $ 4,404 | $ 241 | $ — |
| Natural gas liquids sales | 15 | 22 | — | — | — |
| Natural gas sales | 766 | 589 | 149 | — | — |
| Total revenues | 43,158 | 14,516 | 4,553 | 241 | — |
| **COSTS AND EXPENSES:** | | | | | |
| 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 |
| Total operating costs and expenses | 58,686 | 12,078 | 7,311 | 196 | 1,247 |
| 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) | — | — | — |
| **Net income (loss)** | (16,295) | 1,968 | (2,758) | 45 | (1,247) |
| Less: | | | | | |
| Preferred stock dividends | (2,112) | — | — | — | — |
| **Net income (loss) attributable to common stockholders** | $(18,407) | $ 1,968 | $(2,758) | $ 45 | $(1,247) |
| 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 |

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

(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.

| | As of December 31, | | | | |
|---|---|---|---|---|---|
| | 2012 | 2011(1) | 2010 | 2009 | 2008 |
| | | | (in thousands) | | |
| **Balance Sheet Data:** | | | | | |
| 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 included from the date of acquisition forward.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | 2009 | 2008 |
| | | | (in thousands) | | |
| **Cash Flow Data:** | | | | | |
| Net cash provided by (used in) operating activities | $ 29,072 | $ 5,546 | $(3,777) | $(1,710) | $ (1,247) |
| Net cash provided by (used in) investing activities | $(181,427) | $(108,005) | $(7,925) | $ 2,734 | $(14,197) |
| Net cash provided by (used in) financing activities | $ 139,661 | $ 165,500 | $11,702 | $(1,024) | $ 15,444 |

### Non-GAAP Financial Measures

*Adjusted EBITDA*

We define Adjusted EBITDA as net income (loss):

- Plus:
  - Interest expense, including realized and unrealized losses on interest rate derivative contracts;
  - Income tax expense (benefit);
  - Depreciation, depletion, and amortization;
  - Accretion of asset retirement obligations;
  - Loss (gain) on sale of oil and natural gas properties;
  - Unrealized losses on derivatives;
  - Impairment of oil and natural gas properties;
  - Stock-based compensation expense; and
  - Other non-recurring items that we deem appropriate.

- Less:
  - Preferred stock dividends;
  - Interest income;
  - Unrealized gains on derivatives; and
  - Other non-recurring items that we deem appropriate.

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

- our operating performance as compared to that of other companies and companies in our industry, without regard to financing methods, capital structure or historical cost basis; and
- our ability to incur and service debt and fund capital expenditures.

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

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

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | **2012** | **2011** | **2010** | **2009** | **2008** |
| **Net income (loss)** | $(16,295) | $ 1,968 | $(2,758) | $ 45 | $(1,247) |
| Less: Preferred stock dividends | (2,112) | — | — | — | — |
| **Net income (loss) attributable to common shares and participating securities** | (18,407) | 1,968 | (2,758) | 45 | (1,247) |
| Plus: | | | | | |
| Interest expense | 99 | — | — | — | — |
| Unrealized losses on derivative instruments | 432 | 480 | — | — | — |
| Depreciation, depletion, amortization and accretion | 15,922 | 4,252 | 1,430 | 415 | — |
| Impairment of oil and natural gas properties | — | — | — | 614 | — |
| Stock-based compensation | 25,542 | — | — | — | — |
| Less: | | | | | |
| Interest income | (74) | (1) | — | — | — |
| Gain on sale of oil and natural gas properties | — | — | — | (2,686) | — |
| **Adjusted EBITDA** | 23,514 | 6,699 | (1,328) | (1,612) | (1,247) |
| **Adjusted EBITDA allocable to participating securities** | (687) | — | — | — | — |
| **Adjusted EBITDA attributable to common stockholders** | $ 22,827 | $ 6,699 | $(1,328) | $(1,612) | $(1,247) |
| **Adjusted EBITDA per common share—basic and diluted(1)** | $ 0.69 | $ 0.30 | $ (0.06) | $ (0.07) | $ (0.06) |
| Weighted average number of unrestricted outstanding common shares used to calculate EBITDA per share—basic and diluted(1) | 33,000 | 22,479 | 22,091 | 22,091 | 22,091 |

(1) 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.

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

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | 2009 | 2008 |
| **Net cash provided by (used in) operating activities** | $29,072 | $5,546 | $(3,777) | $(1,710) | $(1,247) |
| Net change in operating assets and liabilities | (3,372) | 1,154 | 2,449 | 98 | — |
| Preferred stock dividends | (2,112) | — | — | — | — |
| Interest income | (74) | (1) | — | — | — |
| **Adjusted EBITDA** | $23,514 | $6,699 | $(1,328) | $(1,612) | $(1,247) |

*Adjusted Net Income*

We present adjusted net income attributable to common stockholders, or Adjusted Net Income, in addition to our reported net income (loss) in accordance with GAAP. This information is provided because management believes exclusion of the impact of our unrealized derivatives not accounted for as cash flow hedges and stock-based compensation expense will help investors compare results between periods, identify operating trends that could otherwise be masked by these items and highlight the impact that commodity price volatility has on our results. We define Adjusted Net Income as net income (loss):

Plus:

- Unrealized losses on derivatives;
- Stock-based compensation expense; and
- Other non-recurring items that we deem appropriate.

Less:

- Preferred stock dividends;
- Unrealized gains on derivatives; and
- Other non-recurring items that we deem appropriate.

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

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | 2009 | 2008 |
| **Net income (loss)** | $(16,295) | $ 1,968 | $(2,758) | $ 45 | $(1,247) |
| Less: Preferred stock dividends | (2,112) | — | — | — | — |
| **Net income (loss) attributable to common shares and participating securities** | (18,407) | 1,968 | (2,758) | 45 | (1,247) |
| Plus: | | | | | |
| Unrealized losses on derivative instruments | 432 | 480 | — | — | — |
| Stock-based compensation | 25,542 | — | — | — | — |
| **Adjusted net income (loss)** | 7,567 | 2,448 | (2,758) | 45 | (1,247) |
| **Adjusted net income allocable to participating securities** | (221) | — | — | — | — |
| **Adjusted net income (loss) attributable to common stockholders** | $ 7,346 | $ 2,448 | $(2,758) | $ 45 | $(1,247) |
| **Adjusted net income (loss) per common share—basic and diluted(1)** | $ 0.22 | $ 0.11 | $ (0.12) | $ — | $ (0.06) |
| Weighted average number of shares outstanding used to calculate adjusted net income per common share—basic and diluted(1) | 33,000 | 22,479 | 22,091 | 22,091 | 22,091 |

(1) 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.

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

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

### Business Overview

We are 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.

#### *Initial Public Offering*

On December 19, 2011, we completed our IPO of 10.0 million shares of common stock, par value $0.01 per share, at a price to the public of $22.00 per share. We received net proceeds of approximately $203.3 million from the sale of the shares of common stock (net of expenses and underwriting discounts and commissions). We paid $50 million of the net proceeds from the offering as partial consideration (together with our issuance to SEP I of approximately 22.1 million shares of our common stock) for the contribution by SEP I of the limited liability company interests in SEP Holdings III and approximately $89 million of the net proceeds as partial consideration (together with our issuance of 909,091 shares of our common stock) for the acquisition of the limited liability company interests in Marquis LLC. SEP Holdings III and Marquis LLC each own interests in certain oil, natural gas and related assets.

#### *Distribution*

On June 19, 2012 and September 17, 2012, SEP I distributed substantially all of the approximately 22.1 million shares of our common stock that SEP I owned to the partners of SEP I. The 21,932,659 shares of common stock distributed to SEP I's partners constituted 66.5% of the issued and outstanding shares of our common stock. This distribution was a return on SEP I's partners' capital contributions to SEP I, thus no consideration was paid to SEP I for the shares of our common stock distributed.

#### *Preferred Stock Offering*

On September 17, 2012, we completed a private placement of 3,000,000 shares of 4.875% Cumulative Perpetual Convertible Preferred Stock, Series A, par value $0.01 per share and liquidation preference of $50 per share, or the Convertible Preferred Stock, which were sold to a group of qualified institutional buyers pursuant to the Rule 144A exemption from registration under the Securities Act. The private placement included 500,000 shares of Convertible Preferred Stock issued pursuant to the exercise of the initial purchasers' option to cover over-allotments. The issue price of each share of the Convertible Preferred Stock was $50.00. We received net proceeds from the private placement of approximately $144.5 million, after deducting initial purchasers' discounts and commissions and offering costs payable by us of approximately $5.5 million.

#### *Basis of Presentation*

Prior to distributing 21,932,659 of its shares of our common stock, SEP I was under common control with us. Because the SEP I Assets were acquired from an "entity under common control with us," we recorded the SEP I Assets retrospectively at their historical carrying values, and no goodwill or other intangible assets were recognized. We acquired the Marquis Assets from parties not under common control with us, and accordingly, the Marquis Assets have been included in our historical financial statements since December 19, 2011. Likewise, our reserve and historical operations data for periods prior to December 19, 2011 provided in this Annual Report on Form 10-K reflect only the SEP I Assets.

Our historical financial statements as of and for the periods prior to December 19, 2011, the date SEP I contributed the SEP I Assets to us, were prepared on a "carve-out" basis from SEP I's accounts. As such, they reflect the historical accounts directly attributable to the properties together with allocations of costs and expenses.

SOG is a private oil and gas company engaged in the exploration for and development of oil and natural gas. SOG has historically acted as the operator of a significant portion of SEP I's oil and natural gas properties. SOG provided all employee, management, and administrative support to SEP I and, for periods prior to December 19, 2011, a proportionate share of SOG's general and administrative costs were allocated to the SEP I Assets. The costs of these services associated with the SEP I Assets were allocated to the SEP I Assets primarily based on the ratio of capital expenditures between the entities to which SOG provides services and the SEP I Assets. However, other factors, such as time spent on general management services and producing property activities, were also considered in the allocation of these costs. Management believes such allocations were reasonable; however, they may not be indicative of the actual expense that would have been incurred had the SEP I Assets been operated as an independent company for periods prior to December 19, 2011. On December 19, 2011, SOG began providing similar types of services to the Company under the services agreement as described in Note 9 of the notes to the consolidated financial statements.

***Our Properties***

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, 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.

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.

*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.

*Outlook*

Beginning in the second half of 2008, the United States and other industrialized countries experienced a significant economic slowdown, which led to a substantial decline in worldwide energy demand. During this same period, North American natural gas supply was increasing as a result of the rise in domestic unconventional natural gas production. The combination of lower energy demand due to the economic slowdown and higher North American natural gas supply resulted in significant declines in oil, NGLs and natural gas prices. While oil and NGL prices started to steadily increase beginning in the second quarter of 2009, natural gas prices remained depressed, recently hitting a 10-year low, due to a continued increase in natural gas supply and weak offsetting demand growth. The outlook for a worldwide economic recovery in 2013 remains uncertain, and the timing of a recovery in worldwide demand for energy is difficult to predict. As a result, it is likely that commodity prices will continue to be volatile during 2013. Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce, the price of our common stock and our access to capital.

Significant factors that may impact future commodity prices include the political and economic developments currently impacting Iran, Egypt, Libya and the Middle East in general; the extent to which members of the OPEC and other oil exporting nations are able to continue to manage oil supply through export quotas; the impact of sovereign debt issues in Europe; and overall North American oil and natural gas supply and demand fundamentals. Although we cannot predict the occurrence of events that will affect future commodity prices or the degree to which these prices will be affected, the prices for any oil, natural gas or NGLs that we produce will generally approximate market prices in the geographic region of the production.

As an oil and natural gas company, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well or formation decreases. Our future growth will depend on our ability to continue to add estimated reserves in excess of our production. Accordingly, we plan to maintain our focus on adding reserves through acquisitions and development projects and improving the economics of producing oil and natural gas from our properties. We expect these acquisition opportunities may come from members of the Sanchez Group, as well as from unrelated third parties. Our ability to add estimated reserves through acquisitions and development projects is dependent on many factors, including our ability to raise capital, obtain regulatory approvals and procure contract drilling rigs and personnel.

## Results of Operations

### *Revenue and Production*

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

| | Year Ended December 31, | | | Increase (Decrease) | | | |
|---|---|---|---|---|---|---|---|
| | | | | 2012 vs 2011 | | 2011 vs 2010 | |
| | 2012 | 2011 | 2010 | $ | % | $ | % |
| **Net Production:** | | | | | | | |
| Oil (mbo) | 417.9 | 145.9 | 55.8 | 272.0 | 186% | 90.1 | 161% |
| Natural gas liquids (mbbl) | 0.7 | 0.5 | — | 0.2 | 40% | 0.5 | * |
| Natural gas (mmcf) | 301.2 | 164.1 | 31.9 | 137.1 | 84% | 132.2 | 414% |
| Total oil equivalent (mboe) | 468.8 | 173.7 | 61.1 | 295.1 | 170% | 112.6 | 184% |
| **Average Sales Price:** | | | | | | | |
| Oil ($ per bo)(1) | $101.40 | $ 95.31 | $78.92 | $ 6.09 | 6% | $16.39 | 21% |
| Natural gas liquids ($ per bbl) | $ 23.26 | $ 47.62 | $ — | $(24.36) | −51% | $47.62 | * |
| Natural gas ($ per mcf) | $ 2.54 | $ 3.59 | $ 4.68 | $ (1.05) | −29% | $(1.09) | −23% |
| Oil equivalent ($ per boe)(1) | $ 92.07 | $ 83.57 | $74.50 | $ 8.50 | 10% | $ 9.07 | 12% |
| **REVENUES:** | | | | | | | |
| Oil sales(1) | $42,377 | $13,905 | $4,404 | $28,472 | 205% | $9,501 | 216% |
| Natural gas liquids sales | 15 | 22 | — | (7) | −32% | 22 | * |
| Natural gas sales | 766 | 589 | 149 | 177 | 30% | 440 | 295% |
| Total revenues | $43,158 | $14,516 | $4,553 | $28,642 | 197% | $9,963 | 219% |

(1) Excludes the impact of oil derivative instruments.

* Not meaningful.

*Net Production.* Production increased from 61.1 mboe in 2010 to 468.8 mboe in 2012 due to our drilling program. The number of gross wells producing at year end and the production for the periods were as follows:

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2012 | | 2011 | | 2010 | |
| | # Wells | mboe | # Wells | mboe | # Wells | mboe |
| Palmetto | 18 | 301.1 | 9 | 150.1 | 6 | 48.7 |
| Maverick | 10 | 87.9 | 3 | 13.7 | 2 | 12.4 |
| Marquis | 3 | 67.4 | — | — | — | — |
| Other | 1 | 12.4 | 1 | 9.9 | — | — |
| Total | 32 | 468.8 | 13 | 173.7 | 8 | 61.1 |

In 2012, 89% of our production was oil and 11% was natural gas compared to 2011 production that was 84% oil and 16% natural gas. In 2010, 91% of our production was oil and 9% was natural gas.

*Average Sales Price.* Our average realized oil price for the year ended December 31, 2012 increased to $101.40 per bo as compared to $95.31 per bo and $78.92 per bo for the years ended December 31, 2011 and 2010, respectively. The average price realized for our natural gas production in 2012 was $2.54 per mcf, 29% lower than the average sales price in 2011 of $3.59 per mcf and 46% lower than the average sales price in 2010 of $4.68 per mcf.

*Revenues.* Oil and natural gas sales revenues totaled approximately $43.2 million, $14.5 million and $4.6 million for the years ended December 31, 2012, 2011 and 2010, respectively. Oil sales revenue for the year ended December 31, 2012 increased $28.5 million with $25.9 million attributable to the increase in production and $2.6 million due to the higher average sales price compared to 2011. For the year ended December 31, 2011 compared to 2010, oil sales revenue increased $9.5 million with $7.1 million attributable to the increase in production and $2.4 million due to the higher average sales price. Natural gas sales revenue for the year ended December 31, 2012 increased approximately $177,000 with $492,000 attributable to the increase in production partially offset by $315,000 due to the lower average sales price compared to 2011. Natural gas sales revenue for the year ended December 31, 2011 increased approximately $440,000 with $619,000 attributable to the increase in production partially offset by $179,000 due to the lower average sales price compared to 2010.

***Costs and Operating Expenses***

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

| | Year Ended December 31, | | | Increase (Decrease) | | | |
|---|---|---|---|---|---|---|---|
| | | | | 2012 vs 2011 | | 2011 vs 2010 | |
| | 2012 | 2011 | 2010 | $ | % | $ | % |
| **OPERATING COSTS AND EXPENSES:** | | | | | | | |
| Oil and natural gas production expenses | $ 3,401 | $ 1,628 | $ 391 | $ 1,773 | 109% | $1,237 | 316% |
| Production and ad valorem taxes | 2,124 | 830 | 214 | 1,294 | 156% | 616 | 288% |
| Depreciation, depletion, amortization and accretion: | | | | | | | |
| Depreciation, depletion and amortization | 15,905 | 4,246 | 1,428 | 11,659 | 275% | 2,818 | 197% |
| Accretion expense | 17 | 6 | 2 | 11 | 183% | 4 | 200% |
| General and administrative (inclusive of stock-based compensation expense of $25,542 for the year ended December 31, 2012) | 37,239 | 5,368 | 5,276 | 31,871 | 594% | 92 | 2% |
| Total operating costs and expenses | 58,686 | 12,078 | 7,311 | 46,608 | 386% | 4,767 | 65% |
| Interest and other income | 74 | 10 | — | 64 | * | 10 | * |
| Interest expense | (99) | — | — | (99) | * | — | * |
| Realized and unrealized losses on derivative instruments | (742) | (480) | — | (262) | 55% | (480) | * |
| Income tax expense | — | — | — | — | * | — | * |

* Not meaningful.

*Oil and Natural Gas Production Expenses.* Oil and natural gas production expenses are the costs incurred to produce our oil and natural gas, as well as the daily costs incurred to maintain our producing properties. Such costs also include field personnel costs, utilities, chemical additives, salt water disposal, maintenance, repairs and occasional well workover expenses related to our oil and natural gas properties. Our oil and natural gas production expenses increased by approximately $1.8 million to approximately $3.4 million for the year ended December 31, 2012, as compared to $1.6 million for the same period in 2011 and $391,000 for the same period in 2010. The increase in oil and natural gas production expenses from 2010 to 2012 is directly attributable to the increase in production resulting from our increased drilling activities in the Eagle Ford Shale.

*Production and Ad Valorem Taxes.* Production and ad valorem taxes are paid on produced oil and natural gas based upon a percentage of gross revenues or at fixed rates established by state or local taxing authorities. Our production and ad valorem taxes totaled $2.1 million, $0.8 million and $0.2 million for the years ended December 31, 2012, 2011 and 2010, respectively. The increase in production and ad valorem taxes over the three year period was due to both the significant increase in production volumes as well as an increase in our average realized prices for oil over the periods.

*Depreciation, Depletion and Amortization.* Depletion, depreciation and amortization reflects the systematic expensing of the capitalized costs incurred in the acquisition, exploration and development of oil and natural gas properties. We use the full-cost method of accounting and accordingly, we capitalize all costs associated with the acquisition, exploration and development of oil and natural gas properties, including unproved and unevaluated property costs. Internal costs are capitalized only to the extent they are directly related to acquisition, exploration and development activities and do not include any costs related to production, selling or general corporate administrative activities. Capitalized costs of oil and natural gas properties are amortized using the units of production method based upon production and estimates of proved oil and natural gas reserve quantities. Unproved and unevaluated property costs are excluded from the amortizable base used to determine depletion, depreciation and amortization expense. Our depletion, depreciation and amortization expenses increased from $1.4 million in 2010 and $4.2 million in 2011 to $15.9 million for the year ended December 31, 2012 due to increases in production and significant development costs incurred.

*General and Administrative Expenses.* Our G&A expenses, including stock-based compensation, totaled $37.2 million for the year ended December 31, 2012 compared to $5.4 million and $5.3 million for the same periods in 2011 and 2010, respectively. G&A expenses, excluding stock-based compensation expense, totaled $11.7 million for 2012, an increase of 118% over the 2011 comparable period. This increase was due to higher costs associated with the new public entity, consisting primarily of audit fees, legal expenses, investor relation costs, consulting and insurance. For the year ended December 31, 2012, we recorded a non-cash stock-based compensation expense of approximately $25.5 million primarily related to the rescission and cancellation of 1.1 million shares of restricted stock during the second quarter of 2012. The restricted stock awards were granted to non-employees such that upon rescission and cancellation, stock-based compensation expense was based on the fair value at the date of cancellation, and the associated unrecognized compensation expense was accelerated and recognized as stock-based compensation expense. At the date of cancellation, the fair value of the stock awards cancelled was approximately $22.3 million, or $20.28 per restricted share.

*Commodity Derivative Transactions.* We apply mark-to-market accounting to our derivative contracts; therefore the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in other income and expense. During the year ended December 31, 2012, we recognized a $0.4 million unrealized loss on our commodity derivative contracts related to the change in fair value of our derivative contracts and a $0.3 million realized loss associated with settlements and/or expirations on our commodity derivative contracts. During the year ended December 31, 2011, we recognized a $0.5 million unrealized loss related to the change in fair value of our derivative contracts. Because our outstanding contracts during 2011 related to 2012 production, no settlements were recognized during 2011. We had no derivative instruments during 2010.

*Income tax expense.* The properties contributed by SEP I were historically owned by a limited partnership that is not a taxable entity and is a disregarded entity for federal income tax purposes. Their taxable income or loss, which may vary substantially from the net income or loss reported in the consolidated statements of operations, was allocated to the limited and general partners of SEP I. With the transfer of the SEP I Assets to us, the SEP I Assets' operations are now subject to federal and state income taxes. At the date of acquisition, we estimated that the aggregate net tax basis of the SEP I Assets exceeded the aggregate net book basis by $24.9 million, resulting in a deferred tax asset of $8.7 million, which was fully offset by a valuation allowance.

Effective December 19, 2011, we began accounting for income taxes using the asset and liability method. Deferred tax assets and liabilities arise from the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Valuation allowances are established when necessary to reduce the deferred tax asset to the amount more likely than not to be recovered. We believe that after considering all the available evidence, both positive and negative, historical and prospective, with greater weight given to historical evidence, there is insufficient evidence to determine that it is more likely than not that the deferred tax assets will be realized and therefore we have established a full valuation allowance to reduce the net deferred tax assets to zero at December 31, 2012 and 2011. We will continue to assess the valuation allowance against deferred tax assets considering all available information obtained in future reporting periods.

**Liquidity and Capital Resources**

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.

On November 16, 2012, we and our subsidiaries, SEP Holdings III and Marquis LLC (collectively referred to with us as the Borrowers), entered into a Credit Agreement, or the First Lien Credit Agreement, dated as of November 15, 2012, among the Borrowers, as borrowers, Capital One, National Association, as administrative agent, sole lead arranger and sole book runner, and each of the other lenders party thereto. The First Lien Credit Agreement provides for a $250 million revolving credit facility which matures November 16, 2015 and is secured by a senior lien on substantially all of the assets of the Borrowers. Availability under the First Lien Credit Agreement is at all times subject to customary conditions and the then applicable borrowing base, which was initially $27.5 million and subject to periodic redeterminations.

Also on November 16, 2012, we entered into a Credit Agreement, or the Second Lien Credit Agreement (collectively referred to with the First Lien Credit Agreement as the Credit Agreements), dated as of November 15, 2012, among the Borrowers, as borrowers, Macquarie Bank Limited, as administrative agent, sole lead arranger and sole book runner, and the other lenders party thereto. The Second Lien Credit Agreement provides for a $250 million term loan facility which matures May 16, 2016 and is secured by a lien on substantially all of the assets of the Borrowers that is junior to those liens under the First Lien Credit Agreement. The Second Lien Credit Agreement provides for an initial commitment of $50 million, subject to customary conditions, with the remaining commitments subject to the approval of the lenders and other customary conditions.

As of December 31, 2012, we had not made any draws under either Credit Agreement, but we intend to use any future borrowings to fund capital expenditures and for general corporate purposes. Under the terms of the Second Lien Credit Agreement, the lenders' $50 million commitment would have expired on January 31, 2013 unless drawn by such date. We drew the available $50 million on January 31, 2013 leaving us with $50 million of outstanding debt. There is no usage under our revolving credit facility.

On February 21, 2013, our available borrowing base under our First Lien Credit Agreement was increased from $27.5 million to $95.0 million. Our Second Lien Credit Agreement remained unchanged.

In connection with the recently announced agreement to purchase assets from Hess, we 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. Availability of the debt financing is conditioned upon, and is intended to be available concurrently with, the closing of the Hess acquisition and will be subject to the satisfaction of various customary closing conditions.

We expect to use our cash on hand, our internally generated cash flow from operations, the proceeds from potential debt and/or equity issuances and/or borrowings under our credit facilities to fund our planned capital expenditure through the end of 2013. Our 2013 capital expenditure program is anticipated to total approximately $347 million, including approximately $327 million for drilling and completion activities. We plan to drill and complete approximately 46 gross (33.5 net) wells in 2013. Approximately $20 million is estimated for facilities, new leases and seismic data.

### Cash Flows

Our cash flows for the years ended December 31, 2012, 2011 and 2010 are as follows (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| **Cash Flow Data:** | | | |
| Net cash provided by (used in) operating activities | $ 29,072 | $ 5,546 | $ (3,777) |
| Net cash used in investing activities | $(181,427) | $(108,005) | $ (7,925) |
| Net cash provided by financing activities | $ 139,661 | $ 165,500 | $11,702 |

*Net Cash Provided by (Used in) Operating Activities.* Net cash provided by operating activities in 2012 was approximately $29.1 million compared to a $5.5 million in 2011 and use of funds in 2010 of $3.8 million. The increase in net cash provided by operating activities in 2012 and 2011 was due primarily to higher revenue resulting from an increase in production as well as higher average oil sales prices as compared to the respective prior year period.

*Net Cash Used in Investing Activities.* Net cash flows used in investing activities totaled approximately $181.4 million for the year ended December 31, 2012 compared to $108.0 million for the year ended December 31, 2011 and $7.9 million for the same period in 2010. For the year ended December 31, 2012, capital expenditures for leasehold and drilling activities totaled $169.7 million, primarily associated with the drilling of 20 wells. In addition we invested $11.6 million in available-for-sale securities. In 2011, we acquired the Marquis Assets which used cash of $89.0 million and incurred capital expenditures for leasehold and drilling activities of $20.6 million. This was partially offset by $1.6 million in proceeds from the sale of certain non-core undeveloped leases. For the year ended December 31, 2010, we incurred capital expenditures for leasehold and drilling activities of $13.8 million, partially offset by $5.9 million in proceeds from the sale of certain non-core undeveloped leases.

*Net Cash Provided by Financing Activities.* Net cash flows provided by financing activities totaled $139.7 million for the year ended December 31, 2012 due primarily to net proceeds from our private placement of Convertible Preferred Stock of approximately $144.5 million, after deducting the initial purchasers' discounts and commissions and offering costs payable by us of approximately $5.5 million. These net proceeds were partially offset by financing costs associated with our new credit facilities of $2.7 million and preferred dividends paid of $2.1 million. For the year ended December 31, 2011, net cash flows provided by financing activities totaled $165.5 million due primarily to our IPO. We received net proceeds of approximately $203.3 million from the sale of the shares of common stock (net of expenses and underwriting discounts and commissions). With proceeds from the IPO, we paid SEP I $50.0 million and paid for the acquisition of the Marquis Assets. Partially offsetting these payments were contributions by SEP I of $12.2 million related to the operation of the oil and natural gas properties prior to our acquisition of the SEP I Assets. For the year ended December 31, 2010, all of our cash provided by financing activities resulted from capital contributions.

### Commitments and Contractual Obligations

As of December 31, 2012, we had no material contractual obligations.

### Off-Balance Sheet Arrangements

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

## Critical Accounting Policies and Estimates

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

### *Oil and Natural Gas Properties*

We use the full cost method of accounting for oil and natural gas properties. Accordingly, all costs associated with acquisition, exploration, and development of oil and natural gas reserves are capitalized.

Under the full cost accounting rules, capitalized costs, less accumulated amortization and related deferred taxes, shall not exceed an amount (the ceiling) equal to: (i) the present value of estimated future net revenues less future production, development, site restoration, and abandonment costs derived based on current costs assuming continuation of existing economic conditions and computed using a discount factor of ten percent; plus (ii) the cost of properties not being amortized; plus (iii) the lower of cost or estimated fair value of unproven properties included in the costs being amortized; less (iv) the related income tax effects. If unamortized costs capitalized within the cost pool exceed the ceiling, the excess is charged to expense and separately disclosed during the period in which the excess occurs. Amounts thus required to be written off are not reinstated for any subsequent increase in the cost center ceiling.

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

In arriving at depletion rates under the unit-of-production method, the quantities of recoverable oil, NGL and natural gas reserves are established based on estimates made by our geologists and engineers, which require significant judgment as does the projection of future production volumes and levels of future costs, including future development costs. In addition, considerable judgment is necessary in determining when unproved properties become impaired and in determining the existence of proved reserves once a well has been drilled. All of these judgments may have significant impact on the calculation of depletion and impairment expense. Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved oil, NGL and natural gas reserves, in which case the gain or loss would be recognized in the statement of operations.

### *Oil and Natural Gas Reserves*

In January 2010, the FASB issued an update to the Oil and Gas topic, which aligns the oil and natural gas reserve estimation and disclosure requirements with the requirements in the SEC's final rule, *Modernization of the Oil and Gas Reporting Requirements*, which we refer to as the Final Rule. The Final Rule was issued on December 31, 2008. The Final Rule was developed to provide investors with a more meaningful and comprehensive understanding of oil and natural gas reserves. The Final Rule permits the use of new technologies to determine proved reserve estimates if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volume estimates. The Final Rule also allows, but does not require, companies to disclose their probable and possible reserves to investors in documents filed with the SEC.

In addition, the Final Rule requires companies to report oil and natural gas reserves using an average price based upon the prior 12 month period rather than a year-end price. The Final Rule became effective for fiscal years ending on or after December 31, 2009.

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

### *Asset Retirement Obligations*

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

### *Revenue Recognition*

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

***Derivative Instruments***

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

***Recent Accounting Pronouncements***

For recent accounting pronouncements, please see Note 2 in the notes to the consolidated financial statements.

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

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

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

### Commodity Price Risk

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

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

As of December 31, 2012, we had four commodity derivative contracts in place covering a portion of our production for 2013. Combined, these four contracts cover an aggregate of 3,500 bopd of oil production. The contracts consist of a 500 bopd $97.10 WTI swap for all of 2013, a 1,000 bopd $88.90 WTI swap for all of 2013, a 1,000 bopd put spread for all of 2013 where we are long a $95 WTI put and short a $75 WTI put, and a 1,000 bopd put spread for the second half of 2013 where we are long a $90 WTI put and short a $75 WTI put.

As of December 31, 2012, the fair value of our commodity derivative contracts was an asset of approximately $2.1 million, all of which is expected to settle during the next twelve months. A 10% increase in the oil index price above the December 31, 2012 price would result in a decrease in the fair value of our commodity derivative contracts of approximately $6.7 million; conversely, a 10% decrease in the oil index price would result in an increase of approximately $7.5 million.

Subsequent to December 31, 2012, we entered into two additional oil derivative contracts covering a portion of our estimated 2014 production. In January 2013, we entered into a commodity derivative contract covering 1,500 bopd of oil production for all of calendar year 2014. The contract is a three-way costless collar consisting of a costless collar (long a $85 WTI put and short a $102.25 WTI call) plus a put (short a $65 WTI put). In February 2013, we entered into a commodity derivative contract covering an additional 1,000 bopd of oil production for all of calendar year 2014. The contract is a three-way costless collar consisting of a costless collar (long a $95 LLS put and short a $107.50 LLS call) plus a put (short a $75 LLS put).

### Interest Rate Risk

We historically have not had any debt. If we incur significant debt in the future we may enter into interest rate derivative contracts on a portion of our then outstanding debt to mitigate the risk of fluctuating interest rates. As of December 31, 2012, we had not made any draws under either Credit Agreement. Under the terms of the Second Lien Credit Agreement, the lenders' $50 million commitment would have expired on January 31, 2013 unless drawn by such date. We drew the available $50 million on January 31, 2013 leaving us with $50 million of outstanding debt. There is currently no usage under our revolving credit facility.

## Item 8. *Financial Statements and Supplementary Data*

The information required by this Item is included in this report as set forth in the "Index to Consolidated Financial Statements" on page F-1 and is incorporated by reference herein.

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

None.

## Item 9A. *Controls and Procedures*

### Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

#### *Evaluation of Disclosure Controls and Procedures*

We carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Rule 13a-15 promulgated pursuant to the Exchange Act. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of the end of the fourth quarter of 2012, our disclosure controls and procedures were effective to provide reasonable assurance that material information required to be disclosed by us in reports that we file or submit under the Exchange Act is appropriately recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

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

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Exchange Act). Even an effective system of internal control over financial reporting, no matter how well designed, has inherent limitations, including the possibility of human error, circumvention of controls or overriding of controls and, therefore, can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of a system of internal control over financial reporting in future periods can change as conditions change.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2012. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control—Integrated Framework. Based on this assessment and such criteria, our management believes that our internal control over financial reporting was effective as of December 31, 2012.

This annual report does not include an attestation report of our independent registered public accounting firm on internal controls due to the exemption provided by the JOBS Act for "emerging growth companies."

**Changes in Internal Control Over Financial Reporting**

There has been no change in our internal control over financial reporting during the quarter ended December 31, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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

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 recently announced agreement to purchase assets from Hess, we 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. Availability of the debt financing is conditioned upon, and is intended to be available concurrently with, the closing of the Hess acquisition and will be subject to the satisfaction of various customary closing conditions.

## PART III

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

Information regarding our directors, executive officers and certain corporate governance items will be included in an amendment to this Form 10-K or in the proxy statement for the 2013 annual meeting of stockholders, in either case, to be filed within 120 days after December 31, 2012, and is incorporated by reference to this report.

### Item 11. *Executive Compensation*

Information regarding executive compensation will be included in an amendment to this Form 10-K or in the proxy statement for the 2013 annual meeting of stockholders and is incorporated by reference to this report.

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

Information regarding beneficial ownership will be included in an amendment to this Form 10-K or in the proxy statement for the 2013 annual meeting of stockholders and is incorporated by reference to this report.

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

Information regarding certain relationships and related transactions and director independence will be included in an amendment to this Form 10-K or in the proxy statement for the 2013 annual meeting of stockholders and is incorporated by reference to this report.

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

Information regarding principal accounting fees and services will be included in an amendment to this Form 10-K or in the proxy statement for the 2013 annual meeting of stockholders and is incorporated by reference to this report.

## GLOSSARY OF SELECTED OIL AND NATURAL GAS TERMS

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

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

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

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

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

***black oil:*** A quality of oil with an API gravity of 40° or less and with a gas-to-oil ratio of 500 cubic feet per barrel or less.

***bo:*** 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

***boe:*** One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six mcf of natural gas to one bo of oil.

***boe/d:*** One boe per day.

***bopd:*** One bo per day.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

***LLS:*** Louisiana light sweet crude.

***mbo:*** One thousand bo.

***mboe:*** One thousand boe.

***mcf:*** One thousand cubic feet of natural gas.

***mmboe:*** One million boe.

***mmbtu:*** One million British thermal units.

***mmcf:*** One million cubic feet of natural gas.

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

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

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

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

***NYMEX:*** New York Mercantile Exchange.

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

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

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

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

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

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

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

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

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

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

***recompletion:*** The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

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

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

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

***spacing:*** The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 40-acre spacing) and is often established by regulatory agencies.

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

***trend:*** A geographic area with hydrocarbon potential.

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

***unproved properties:*** Properties with no proved reserves.

***volatile oil:*** A quality of oil with an API gravity greater than 40° and with a gas-to-oil ratio of greater than 500 cubic feet per barrel.

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

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

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

***WTI:*** West Texas Intermediate.

## PART IV

**Item 15.** ***Exhibits and Financial Statement Schedules***

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

(1) Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

(2) Financial Statement Schedules:

None.

(3) Exhibits:

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

| Exhibit No. | Description of Exhibit |
|---|---|
| 2.1 | Contribution, Conveyance and Assumption Agreement, dated as of December 19, 2011, by and between Sanchez Energy Partners I, LP and Sanchez Energy Corporation (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference). |
| 2.2 | Contribution Agreement, dated November 8, 2011, by and between Ross Exploration, Inc. and Sanchez Energy Corporation (filed as Exhibit 2.2 to Amendment No. 3 to the Company's registration statement on Form S-1 (File. No. 333-176613) on November 25, 2011, and incorporated herein by reference). |
| 3.1 | Amended and Restated Certificate of Incorporation dated as of December 13, 2011 (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on December 19, 2011, and incorporated herein by reference). |
| 3.2 | Amended and Restated Bylaws dated as of December 13, 2011 (filed as Exhibit 3.2 to the Company's Current Report on Form 8-K on December 19, 2011, and incorporated herein by reference). |
| 3.3 | Certificate of Designations of 4.875% Cumulative Perpetual Convertible Preferred Stock, Series A (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on September 18, 2012, and incorporated herein by reference). |
| 4.1 | Form of Common Stock Certificate (filed as Exhibit 4.1 to Amendment No. 3 to the Company's registration statement on Form S-1 (File. No. 333-176613) on November 25, 2011, and incorporated herein by reference). |
| 10.1 | Services Agreement, dated as of December 19, 2011, by and between Sanchez Oil & Gas Corporation and Sanchez Energy Corporation (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference). |
| 10.2 | Geophysical Seismic Data Use License Agreement, dated as of December 19, 2011, by and among Sanchez Oil & Gas Corporation, Sanchez Energy Corporation, SEP Holdings III, LLC and SN Marquis LLC (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference). |

| Exhibit No. | Description of Exhibit |
|---|---|
| 10.3 | Registration Rights Agreement, dated as of December 19, 2011, by and between Sanchez Energy Corporation and Sanchez Energy Partners I, LP (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference). |
| 10.4 | Indemnification Agreement, dated as of December 19, 2011, between Sanchez Energy Corporation and Antonio R. Sanchez, III (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference). |
| 10.5 | Indemnification Agreement, dated as of December 19, 2011, between Sanchez Energy Corporation and Michael G. Long (filed as Exhibit 10.5 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference). |
| 10.6 | Indemnification Agreement, dated as of December 19, 2011, between Sanchez Energy Corporation and Gilbert A. Garcia (filed as Exhibit 10.6 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference). |
| 10.7* | Sanchez Energy Corporation Amended and Restated 2011 Long Term Incentive Plan (filed as Exhibit 99.1 to the Company's Current Report on Form 8-K on May 24, 2012, and incorporated herein by reference). |
| 10.8* | Form of Restricted Stock Agreement for employees (filed as Exhibit 10.1 to the Company's registration statement on Form S-8 (File No. 333-178920) on January 6, 2012, and incorporated herein by reference). |
| 10.9* | Form of Restricted Stock Agreement for non-employee directors (filed as Exhibit 10.2 to the Company's registration statement on Form S-8 (File No. 333-178920) on January 6, 2012, and incorporated herein by reference). |
| 10.10* | Form of Restricted Stock Agreement for Antonio R. Sanchez, III (filed as Exhibit 10.3 to the Company's registration statement on Form S-8 (File No. 333-178920) on January 6, 2012, and incorporated herein by reference). |
| 10.11 | Indemnification Agreement, dated as of March 9, 2012, between Sanchez Energy Corporation and Greg Colvin (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on March 14, 2012, and incorporated herein by reference). |
| 10.12 | Indemnification Agreement, dated as of March 9, 2012, between Sanchez Energy Corporation and Kirsten A. Hink (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on March 14, 2012, and incorporated herein by reference). |
| 10.13 | Purchase Agreement, dated September 12, 2012, among Sanchez Energy Corporation and RBC Capital Markets, LLC, as representative of the several initial purchasers named therein (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on September 18, 2012, and incorporated herein by reference). |
| 10.14 | Credit Agreement, dated as of November 15, 2012, among Sanchez Energy Corporation, SEP Holdings III, LLC and SN Marquis LLC, as borrowers, Capital One, National Association, as administrative agent for the lenders, and each of the lenders from time to time party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on November 23, 2012, and incorporated herein by reference). |

| Exhibit No. | Description of Exhibit |
|---|---|
| 10.15 | Second Lien Term Credit Agreement, dated as of November 15, 2012, among Sanchez Energy Corporation, SEP Holdings III, LLC and SN Marquis LLC, as borrowers, Macquarie Bank Limited, as administrative agent for the lenders, and each of the Lenders from time to time party thereto (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on November 23, 2012, and incorporated herein by reference). |
| 10.16 | Indemnification Agreement, dated as of November 27, 2012, between Sanchez Energy Corporation and A. R. Sanchez, Jr. (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on December 3, 2012, and incorporated herein by reference). |
| 10.17 | Indemnification Agreement, dated as of November 27, 2012, between Sanchez Energy Corporation and Alan G. Jackson (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on December 3, 2012, and incorporated herein by reference). |
| 10.18 | Indemnification Agreement, dated as of November 27, 2012, between Sanchez Energy Corporation and Joseph R. DeDominic (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K on December 3, 2012, and incorporated herein by reference). |
| 10.19* | Form of Restricted Stock Agreement for Joseph R. DeDominic (filed as Exhibit 10.5 to the Company's Current Report on Form 8-K on December 3, 2012, and incorporated herein by reference). |
| 21.1(a) | List of Subsidiaries of Sanchez Energy Corporation. |
| 23.1(a) | Consent of BDO USA, LLP. |
| 23.2(a) | Consent of Ryder Scott Company, L.P. |
| 31.1(a) | Sarbanes-Oxley Section 302 certification of Principal Executive Officer. |
| 31.2(a) | Sarbanes-Oxley Section 302 certification of Principal Financial Officer. |
| 32.1(b) | Sarbanes-Oxley Section 906 certification of Principal Executive Officer. |
| 32.2(b) | Sarbanes-Oxley Section 906 certification of Principal Financial Officer. |
| 99.1(a) | Ryder Scott Company, L.P. Summary of December 31, 2012 Reserves. |
| 101.INS(b) | —XBRL Instance Document. |
| 101.SCH(b) | —XBRL Taxonomy Extension Schema Document. |
| 101.CAL(b) | —XBRL Taxonomy Extension Calculation Linkbase Document. |
| 101.DEF(b) | —XBRL Taxonomy Extension Definition Linkbase Document. |
| 101.LAB(b) | —XBRL Taxonomy Extension Labels Linkbase Document. |
| 101.PRE(b) | —XBRL Taxonomy Extension Presentation Linkbase Document. |

(a) Filed herewith.

(b) Furnished herewith.

* Management contract or compensatory plan or arrangement.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, on March 18, 2013.

SANCHEZ ENERGY CORPORATION

By: /s/ ANTONIO R. SANCHEZ, III

Antonio R. Sanchez, III
*President and Chief Executive Officer*

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

| Signature | Title | Date |
|---|---|---|
| /s/ ANTONIO R. SANCHEZ, III<br>Antonio R. Sanchez, III | President, Chief Executive Officer and Director (Principal Executive Officer) | March 18, 2013 |
| /s/ MICHAEL G. LONG<br>Michael G. Long | Senior Vice President and Chief Financial Officer (Principal Financial Officer) | March 18, 2013 |
| /s/ KIRSTEN A. HINK<br>Kirsten A. Hink | Vice President and Principal Accounting Officer (Principal Accounting Officer) | March 18, 2013 |
| /s/ A. R. SANCHEZ, JR.<br>A. R. Sanchez, Jr. | Executive Chairman of the Board of Directors | March 18, 2013 |
| /s/ GILBERT A. GARCIA<br>Gilbert A. Garcia | Director | March 18, 2013 |
| /s/ GREG COLVIN<br>Greg Colvin | Director | March 18, 2013 |
| /s/ ALAN G. JACKSON<br>Alan G. Jackson | Director | March 18, 2013 |

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

### INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

***Sanchez Energy Corporation***

***Report of Independent Registered Public Accounting Firm***

To the Board of Directors and Stockholders
Sanchez Energy Corporation
Houston, Texas

We have audited the accompanying consolidated balance sheets of Sanchez Energy Corporation (the "Company") as of December 31, 2012 and 2011 and the related consolidated statements of operations, parent net investment/stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2, the consolidated financial statements include the accounts of certain oil and natural gas properties (the "SEP I Assets") transferred by Sanchez Energy Partners I, LP, a related entity, to the Company on December 19, 2011, which were not a stand-alone entity. The accounts of the SEP I Assets reflect the assets, liabilities, revenues, and expenses directly attributable to the SEP I Assets, as well as allocations deemed reasonable by management, to present the financial position, results of operations and cash flows of the SEP I Assets on a stand-alone basis and do not necessarily reflect the financial position, results of operations and cash flows had the SEP I Assets operated as a stand-alone entity during the periods presented and, accordingly, may not be indicative of the Company's future performance.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Sanchez Energy Corporation at December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

/s/ BDO USA, LLP

Houston, Texas
March 18, 2013

**Sanchez Energy Corporation**

**Consolidated Balance Sheets**

**(in thousands, except share and per share amounts)**

| | As of December 31, 2012 | As of December 31, 2011 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 50,347 | $ 63,041 |
| Available-for-sale investments | 11,591 | — |
| Oil and natural gas receivables | 10,435 | 1,193 |
| Fair value of derivative instruments | 2,145 | 1,461 |
| Other current assets | 438 | 327 |
| Total current assets | 74,956 | 66,022 |
| Oil and natural gas properties, at cost, using the full cost method: | | |
| Unproved oil and natural gas properties | 138,937 | 126,201 |
| Proved oil and natural gas properties | 232,523 | 31,836 |
| Total oil and natural gas properties | 371,460 | 158,037 |
| Less: Accumulated depreciation, depletion, amortization and impairment | (22,605) | (6,703) |
| Total oil and natural gas properties, net | 348,855 | 151,334 |
| Other assets: | | |
| Debt issuance costs (net of accumulated amortization of $99 and zero as of December 31, 2012 and 2011, respectively) | 2,595 | — |
| Other assets | 168 | — |
| Total assets | $426,574 | $217,356 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| Current liabilities: | | |
| Accounts payable—related entities | $ 13,454 | $ 1,606 |
| Accrued liabilities | 44,828 | 526 |
| Derivative premium liabilities | 1,003 | — |
| Total current liabilities | 59,285 | 2,132 |
| Asset retirement obligation | 546 | 83 |
| Total liabilities | 59,831 | 2,215 |
| Commitments and contingencies (Note 12) | | |
| Stockholders' equity: | | |
| Preferred stock ($0.01 par value, 15,000,000 shares authorized; 3,000,000 and zero shares of 4.875% Cumulative Perpetual Convertible Preferred Stock, Series A, issued and outstanding as of December 31, 2012 and 2011, respectively) | 30 | — |
| Common stock ($0.01 par value, 150,000,000 shares authorized; 33,762,400 and 33,000,000 shares issued and outstanding as of December 31, 2012 and 2011, respectively) | 338 | 330 |
| Additional paid-in capital | 385,086 | 215,115 |
| Accumulated deficit | (18,711) | (304) |
| Total stockholders' equity | 366,743 | 215,141 |
| Total liabilities and stockholders' equity | $426,574 | $217,356 |

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

**Sanchez Energy Corporation**

**Consolidated Statements of Operations**

**(in thousands, except per share amounts)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2012** | **2011** | **2010** |
| **REVENUES:** | | | |
| Oil sales | $ 42,377 | $13,905 | $ 4,404 |
| Natural gas liquids sales | 15 | 22 | — |
| Natural gas sales | 766 | 589 | 149 |
| Total revenues | 43,158 | 14,516 | 4,553 |
| **OPERATING COSTS AND EXPENSES:** | | | |
| Oil and natural gas production expenses | 3,401 | 1,628 | 391 |
| Production and ad valorem taxes | 2,124 | 830 | 214 |
| Depreciation, depletion and amortization | 15,905 | 4,246 | 1,428 |
| Accretion | 17 | 6 | 2 |
| General and administrative (inclusive of stock-based compensation of $25,542 for 2012) | 37,239 | 5,368 | 5,276 |
| Total operating costs and expenses | 58,686 | 12,078 | 7,311 |
| Operating income (loss) | (15,528) | 2,438 | (2,758) |
| Other income (expense): | | | |
| Interest and other income | 74 | 10 | — |
| Interest expense | (99) | — | — |
| Realized and unrealized losses on derivative instruments | (742) | (480) | — |
| **Net income (loss)** | (16,295) | 1,968 | (2,758) |
| Less: | | | |
| Preferred stock dividends | (2,112) | — | — |
| **Net income (loss) attributable to common stockholders** | $(18,407) | $ 1,968 | $(2,758) |
| Net income (loss) per common share—basic and diluted | $ (0.56) | $ 0.09 | $ (0.12) |
| Weighted average number of shares used to calculate net income (loss) attributable to common stockholders—basic and diluted | 33,000 | 22,479 | 22,091 |

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

## Sanchez Energy Corporation

## Consolidated Statements of Parent Net Investment / Stockholders' Equity

## (in thousands)

| | Series A Preferred Stock | | Common Stock | | Additional Paid-in Capital | Accumulated Deficit | Parent Net Investment | Total Stockholders' Equity |
|---|---|---|---|---|---|---|---|---|
| | Shares | Amount | Shares | Amount | | | | |
| **BALANCE, December 31, 2009** | — | $— | — | $ — | $ — | $ — | $ 13,218 | $ 13,218 |
| Contribution by parent | — | — | — | — | — | — | 11,702 | 11,702 |
| Net loss | — | — | — | — | — | — | (2,758) | (2,758) |
| **BALANCE, December 31, 2010** | — | — | — | — | — | — | 22,162 | 22,162 |
| Contribution by parent | — | — | — | — | — | — | 12,186 | 12,186 |
| Net income from January 1 through December 18, 2011 | — | — | — | — | — | — | 2,272 | 2,272 |
| Distribution to parent | — | — | — | — | — | — | (50,000) | (50,000) |
| Accounts receivable distributed to parent | — | — | — | — | — | — | (2,494) | (2,494) |
| Accounts payable assumed by parent | — | — | — | — | — | — | 8,005 | 8,005 |
| **BALANCE, December 18, 2011, prior to purchase of properties** | — | — | — | — | — | — | (7,869) | (7,869) |
| Purchase of oil and natural gas properties from SEP I in exchange for common stock | — | — | 22,091 | 221 | (8,090) | — | 7,869 | — |
| Purchase of oil and natural gas properties from Ross Exploration in exchange for common stock | — | — | 909 | 9 | 19,991 | — | — | 20,000 |
| Shares issued in initial public offering, net of offering costs | — | — | 10,000 | 100 | 203,214 | — | — | 203,314 |
| Net loss from December 19 through December 31, 2011 | — | — | — | — | — | (304) | — | (304) |
| **BALANCE, December 31, 2011** | — | — | 33,000 | 330 | 215,115 | (304) | — | 215,141 |
| Issuance of preferred stock, net of offering costs of $5,533 | 3,000 | 30 | — | — | 144,437 | — | — | 144,467 |
| Preferred stock dividends | — | — | — | — | — | (2,112) | — | (2,112) |
| Restricted stock awards, net of forfeitures and cancellations | — | — | 762 | 8 | (8) | — | — | — |
| Stock-based compensation | — | — | — | — | 25,542 | — | — | 25,542 |
| Net loss | — | — | — | — | — | (16,295) | — | (16,295) |
| **BALANCE, December 31, 2012** | 3,000 | $30 | 33,762 | $338 | $385,086 | $(18,711) | $ — | $366,743 |

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

**Sanchez Energy Corporation**

**Consolidated Statements of Cash Flows**

**(in thousands)**

| | Year Ended December 31, 2012 | 2011 | 2010 |
|---|---|---|---|
| **CASH FLOWS FROM OPERATING ACTIVITIES:** | | | |
| Net income (loss) | $ (16,295) | $ 1,968 | $ (2,758) |
| Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities: | | | |
| Depreciation, depletion and amortization | 15,905 | 4,246 | 1,428 |
| Asset retirement obligation accretion | 17 | 6 | 2 |
| Stock-based compensation | 25,542 | — | — |
| Unrealized losses on derivative instruments | 432 | 480 | — |
| Amortization of deferred financing costs | 99 | — | — |
| Changes in operating assets and liabilities: | | | |
| Accounts receivable | (8,922) | (962) | (2,619) |
| Other current assets | (111) | (327) | — |
| Price risk management activities, net | (434) | (1,932) | — |
| Accounts payable—related entities | 11,848 | 1,606 | — |
| Accrued liabilities | 991 | 461 | 170 |
| Net cash provided by (used in) operating activities | 29,072 | 5,546 | (3,777) |
| **CASH FLOWS FROM INVESTING ACTIVITIES:** | | | |
| Payments for oil and natural gas properties | (169,665) | (20,578) | (13,848) |
| Payments for other property and equipment | (171) | — | — |
| Proceeds from sale of oil and natural gas properties | — | 1,587 | 5,923 |
| Acquisition of Marquis Assets | — | (89,014) | — |
| Investment in available-for-sale securities | (11,591) | — | — |
| Net cash used in investing activities | (181,427) | (108,005) | (7,925) |
| **CASH FLOWS FROM FINANCING ACTIVITIES:** | | | |
| Issuance of common stock | — | 220,000 | — |
| Issuance of preferred stock | 150,000 | — | — |
| Payments for offering costs | (5,533) | (16,686) | — |
| Financing costs | (2,694) | — | — |
| Preferred dividends paid | (2,112) | — | — |
| Net investment by (distribution to) parent | — | (37,814) | 11,702 |
| Net cash provided by financing activities | 139,661 | 165,500 | 11,702 |
| Increase (decrease) in cash and cash equivalents | (12,694) | 63,041 | — |
| Cash and cash equivalents, beginning of period | 63,041 | — | — |
| Cash and cash equivalents, end of period | $ 50,347 | $ 63,041 | $ — |
| **NON-CASH INVESTING AND FINANCING ACTIVITIES:** | | | |
| Asset retirement obligation | $ 446 | $ 17 | $ 47 |
| Change in accrued capital expenditures | 43,311 | 3,518 | 4,326 |
| Accounts receivable distributed to parent | — | 2,494 | — |
| Accounts payable assumed by parent | — | (8,005) | — |
| Purchase of oil and natural gas properties from Ross Exploration in exchange for common stock | — | 20,000 | — |
| Deferred premium liabilities | 1,003 | — | — |

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

**Sanchez Energy Corporation**

**Notes to the Consolidated Financial Statements**

## Note 1. Organization and Business

Sanchez Energy Corporation (together with its consolidated subsidiaries, the "Company," "we," "our," "us" or similar terms) is an independent exploration and production company focused on the acquisition, exploration, and development of unconventional oil and natural gas resources primarily in the Eagle Ford Shale in South Texas. As of December 31, 2012, the Company had accumulated acreage in the Eagle Ford Shale in Gonzales, Zavala, Frio, Fayette, Lavaca, Atascosa, Webb and DeWitt Counties of South Texas. In addition, the Company has properties located in the Haynesville Shale in north central Louisiana, which is primarily a natural gas play, and an undeveloped acreage position in Northern Montana, which the Company believes may be prospective for the Heath, Three Forks and Bakken Shales.

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

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

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

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

On June 19, 2012 and September 17, 2012, SEP I distributed substantially all of the approximately 22.1 million shares of the Company's common stock that SEP I owned to the partners of SEP I (the "Distribution"). The 21,932,659 shares of common stock distributed to SEP I's partners constituted 66.5% of the issued and outstanding shares of the Company's common stock at that date. The

**Note 1. Organization and Business (Continued)**

Distribution was a return on SEP I's partners' capital contributions to SEP I, thus no consideration was paid to SEP I for the shares of the Company's common stock distributed. As of June 19, 2012, the Company is no longer under common control with SEP I.

On September 17, 2012, the Company completed a private placement of 3,000,000 shares of 4.875% Cumulative Perpetual Convertible Preferred Stock, Series A, par value $0.01 per share and liquidation preference of $50 per share (the "Convertible Preferred Stock"), which were sold to a group of qualified institutional buyers pursuant to the Rule 144A exemption from registration under the Securities Act of 1933, as amended (the "Securities Act"). The private placement included 500,000 shares of Convertible Preferred Stock issued pursuant to the exercise of the initial purchasers' option to cover over-allotments. The issue price of each share of the Convertible Preferred Stock was $50.00. The Company received net proceeds from the private placement of approximately $144.5 million, after deducting initial purchasers' discounts and commissions and offering costs payable by the Company of approximately $5.5 million.

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

***Basis of Presentation***

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

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

For periods prior to December 19, 2011, the consolidated financial statements were prepared on a "carve-out" basis from SEP I's accounts and reflect the historical accounts directly attributable to the SEP I Assets together with allocations of costs and expenses. The financial statements for periods prior to December 19, 2011 may not be indicative of future performance and may not reflect what the results of operations, financial position, and cash flows would have been had the SEP I Assets been operated as an independent company.

SOG is a private oil and gas company engaged in the exploration for and development of oil and natural gas. SOG has historically acted as the operator of a significant portion of SEP I's oil and natural gas properties. SOG provided all employee, management, and administrative support to SEP I and, for periods prior to December 19, 2011, a proportionate share of SOG's general and administrative costs were allocated to the SEP I Assets. The costs of these services associated with the SEP I Assets were allocated to the SEP I Assets primarily based on the ratio of capital expenditures between the entities to which SOG provides services and the SEP I Assets. However, other factors, such as time spent on general management services and producing property activities, were also considered in the allocation of these costs. Management believes such allocations were reasonable; however, they may not be indicative of the actual expense that would have been incurred had the SEP I Assets been operated as an independent company for periods prior to December 19, 2011. On December 19, 2011, SOG began providing similar types of services to the Company under the services agreement as described below (Note 9).

**Note 2. Basis of Presentation and Summary of Significant Accounting Policies (Continued)**

***Principles of Consolidation***

The Company's consolidated financial statements include the accounts of the Company and its subsidiaries. All intercompany balances and transactions have been eliminated.

***Use of Estimates***

The accompanying consolidated financial statements are prepared in conformity with U.S. GAAP, which requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil and natural gas reserves and related cash flow estimates used in the depletion and impairment of oil and natural gas properties, the evaluation of unproved properties for impairment, the fair value of commodity derivative contracts and asset retirement obligations, accrued oil and natural gas revenues and expenses and the allocation of general and administrative expenses. Actual results could differ materially from those estimates.

***Reclassifications***

Certain reclassifications have been made to the 2011 and 2010 consolidated financial statements to conform to the 2012 presentation. These reclassifications were not material to the accompanying consolidated financial statements.

***Cash Equivalents***

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

***Available-for-Sale Investments***

At December 31, 2012, the Company held certain investments in marketable securities as a means of temporarily investing the proceeds from its Convertible Preferred Stock offering until the funds are needed for operating purposes. The Company considers all highly liquid interest-earning investments with a maturity of three months or less at the date of purchase to be cash equivalents. Investments with original maturities of greater than three months are accounted for as "available-for-sale" investments. At December 31, 2012 these investments consisted of corporate notes and bonds and investment grade commercial paper. These investments are reflected at their fair value, based on quoted market prices, with unrealized gains and losses recorded in accumulated other comprehensive income until the investments are sold, at which time the realized gains and losses are included in the results of operations. As of December 31, 2012, there were no gains or losses recorded in accumulated other comprehensive income due to the fact that the fair value of these investments approximated the costs paid for these securities. The Company did not have similar investments during prior periods.

***Oil and Natural Gas Receivables***

All of the Company's receivables arise from sales of oil, NGLs or natural gas. The Company does not have any off-balance-sheet credit exposure related to its customers. Receivables from the sale of oil and natural gas are generally unsecured. Allowances for doubtful accounts are determined based on management's assessment of the creditworthiness of the customer. Receivables are considered past due

**Note 2. Basis of Presentation and Summary of Significant Accounting Policies (Continued)**

if full payment is not received by the contractual due date. Past due accounts are written off against the allowance for doubtful accounts only after all the collection attempts have been exhausted. At December 31, 2012 and 2011, management believed that all balances were fully collectible and no allowance for doubtful accounts was deemed necessary.

*Oil and Natural Gas Properties*

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

*Full Cost Ceiling Test*—Capitalized costs (net of accumulated depreciation, depletion and amortization and deferred income taxes) of proved oil and natural gas properties are subject to a full cost ceiling limitation. The ceiling limits these costs to an amount equal to the present value, discounted at 10%, of estimated future net cash flows from estimated proved reserves less estimated future operating and development costs, abandonment costs (net of salvage value) and estimated related future income taxes. In accordance with Securities and Exchange Commission ("SEC") rules, the oil and natural gas prices used to calculate the full cost ceiling are the 12-month average prices, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. Prices are adjusted for "basis" or location differentials. Prices are held constant over the life of the reserves. If unamortized costs capitalized within the cost pool exceed the ceiling, the excess is charged to expense and separately disclosed during the period in which the excess occurs. Amounts thus required to be written off are not reinstated for any subsequent increase in the cost center ceiling. No impairment expense was recorded for the years ended December 31, 2012, 2011 or 2010.

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

In arriving at depletion rates under the units-of-production method, the quantities of recoverable oil and natural gas reserves are established based on estimates made by internal and third party

**Note 2. Basis of Presentation and Summary of Significant Accounting Policies (Continued)**

geologists and engineers, which require significant judgment as does the projection of future production volumes and levels of future costs, including future development costs. In addition, considerable judgment is necessary in determining when unproved properties become impaired and in determining the existence of proved reserves once a well has been drilled. All of these judgments may have significant impact on the calculation of depletion and impairment expense.

In November 2010, certain unevaluated oil and natural gas acreage was sold for cash of $5.9 million in a transaction not considered significant under the full cost accounting rules, resulting in a reduction to the full cost pool by the amount of the proceeds. In February 2011, certain unevaluated oil and natural gas acreage was sold for cash of $1.6 million in a transaction not considered significant under the full cost accounting rules, resulting in a reduction to the full cost pool by the amount of the proceeds.

*Unproved Properties*—Costs associated with unproved properties and properties under development are excluded from the full cost amortization base until the properties have been evaluated. Additionally, the costs associated with seismic data, leasehold acreage, and wells currently drilling are also initially excluded from the amortization base. Unproved properties are identified on a project basis, with a project being an area in which significant leasehold interests are acquired within a contiguous area. Unproved properties are reviewed periodically by management and transferred into the full cost pool subject to amortization when management determines that a project area has been evaluated through drilling operations or a thorough geologic evaluation.

Based on management's review, 18%, 2% and 16% of the unproved property balance at December 31, 2012 is expected to be added to the amortization base during the years 2013, 2014 and 2015, respectively. The remaining balances in unproved properties relate to project areas that will not be thoroughly evaluated until after 2015, and represent leasehold interests that have expiration dates beginning in 2016.

The table below sets forth the cost of unproved properties excluded from the amortization base as of December 31, 2012 and notes the year in which the associated costs were incurred (in thousands):

| | Year of Acquisition | | | | | |
|---|---|---|---|---|---|---|
| | 2008 | 2009 | 2010 | 2011 | 2012 | Total |
| Leasehold acquisition costs | $1,483 | $11 | $822 | $105,969 | $ 8,974 | $117,259 |
| Exploration costs | 254 | 33 | — | — | 13,787 | 14,074 |
| Development costs | — | — | — | — | 7,604 | 7,604 |
| Total | $1,737 | $44 | $822 | $105,969 | $30,365 | $138,937 |

***Oil and Natural Gas Reserve Quantities***

The Company's most significant estimates relate to its proved oil and natural gas reserves. The estimates of oil and natural gas reserves as of December 31, 2012, 2011 and 2010 are based on reports prepared by a third party engineering firm, Ryder Scott Company, L.P. ("Ryder Scott").

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

**Note 2. Basis of Presentation and Summary of Significant Accounting Policies (Continued)**

provided to it by management and other information available, including information from the operators of the property.

In January 2010, the Financial Accounting Standards Board ("FASB") issued an update to the Oil and Gas topic, which aligned the oil and natural gas reserve estimation and disclosure requirements with the requirements in the SEC's final rule, *Modernization of the Oil and Gas Reporting Requirements* (the "Final Rule"). The Final Rule was issued on December 31, 2008 and provided investors with a more meaningful and comprehensive understanding of oil and natural gas reserves.

The Final Rule permits the use of new technologies to determine proved reserve estimates if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volume estimates. The Final Rule also allows, but does not require, companies to disclose their probable and possible reserves to investors in documents filed with the SEC.

In addition, the disclosure guidelines require companies to report oil and natural gas reserves using an average price based upon the prior 12 month first day of the month price rather than a period-end price. The Final Rule became effective for fiscal years ending on or after December 31, 2009.

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

***Environmental Expenditures***

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

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

**Note 2. Basis of Presentation and Summary of Significant Accounting Policies (Continued)**

Management believes the Company is currently in compliance with all applicable federal, state and local regulations associated with its properties. Accordingly, no environmental remediation liability or loss associated with the Company's properties was recorded as of December 31, 2012 and 2011.

***Accrued Liabilities***

The following information summarizes accrued liabilities as of December 31, 2012 and 2011 (in thousands):

| | As of December 31, | |
|---|---|---|
| | 2012 | 2011 |
| Capital expenditures | $43,560 | $249 |
| General and administrative costs | 268 | 170 |
| Production taxes | 471 | 56 |
| Ad valorem taxes | 114 | 5 |
| Lease operating expenses | 415 | 46 |
| Total accrued liabilities | $44,828 | $526 |

***Asset Retirement Obligations***

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

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

The following table is a reconciliation of the beginning and ending balance associated with the asset retirement obligation (in thousands):

| | 2012 | 2011 |
|---|---|---|
| Abandonment liability as of January 1, | $ 83 | $60 |
| Liabilities incurred during period | 446 | 17 |
| Accretion expense | 17 | 6 |
| Abandonment liability as of December 31, | $546 | $83 |

## Note 2. Basis of Presentation and Summary of Significant Accounting Policies (Continued)

### *Revenue Recognition*

Oil, NGL and natural gas sales are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred, and collectability of the revenue is probable. Delivery occurs and title is transferred when production has been delivered to a pipeline, railcar or truck, or a tanker lifting has occurred. The sales method of accounting is used for oil, NGL and natural gas sales. Oil and natural gas imbalances are generated on properties for which two or more owners have the right to take production "in-kind" and, in doing so, take more or less than their respective entitled percentage. As of December 31, 2012 and 2011, there were no oil and natural gas imbalances.

### *Sales to Major Customers*

The Company's oil, NGL and natural gas production was sold to certain customers representing 10% or more of its total revenues for the years ended December 31, 2012, 2011 and 2010 as listed below:

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| Customer A | 63% | 22% | — |
| Customer B | 18% | 6% | 19% |
| Customer C | 16% | — | — |
| Customer D | — | 68% | 81% |

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

### *General and Administrative Expenses*

The financial statements reflect an allocated portion of the actual costs incurred by SOG in general and administrative ("G&A") expenses through December 18, 2011. Prior to December 19, 2011, a wide range of formulas for G&A allocation were considered and recorded in association with the operation of the SEP I Assets. Management believes the most accurate and transparent method of allocating G&A expenses is based on the approximate ratio of capital expenditures between the entities to which SOG provides services. Other factors, such as time spent on general management services and producing property activities, were also considered in the allocation of these costs. Using this method, and considering other factors, G&A expense allocated to the SEP I Assets for the period from January 1, 2011 through December 18, 2011 and the year ended December 31, 2010 was approximately \$4.3 million and \$5.1 million, respectively.

On December 19, 2011, the Company entered into a services agreement and other related agreements with SOG, pursuant to which SOG (directly or through its subsidiaries) agreed to provide the Company with the services and data that the Company believes are necessary to manage, operate and grow its business, and the Company agreed to reimburse SOG for all direct and indirect costs incurred on its behalf.

**Note 2. Basis of Presentation and Summary of Significant Accounting Policies (Continued)**

***Fair Value of Financial Instruments***

Financial instruments not carried at fair value consist of oil and natural gas receivables, accounts payables and accrued liabilities. The carrying amounts of these financial instruments approximate fair value due to the highly liquid nature of these short-term instruments.

Cash and cash equivalents include all cash balances and any highly liquid investments with an original maturity of 90 days or less. The carrying amount approximates fair value because of the short maturity of these instruments. The Company also holds certain investments in marketable securities as a means of temporarily investing proceeds until funds are needed for operating purposes. These investments are accounted for as "available-for-sale" investments. The investments are reflected at their fair value, based on quoted market prices, with unrealized gains and losses recorded in accumulated other comprehensive income until the investments are sold, at which time the realized gains and losses are included in the results of operations. As of December 31, 2012, there were no gains or losses recorded in accumulated other comprehensive income due to the fact that the fair value of these investments approximated the costs paid for these securities. The Company did not have similar investments during prior periods.

***Derivative Instruments***

The Company utilizes derivative instruments in order to manage price risk associated with future crude oil and natural gas production. Management sets and implements all of the hedging policies, including volumes, types of instruments and counterparties, on a monthly basis. The Company recognizes all derivatives as either assets or liabilities, measured at fair value, and recognizes changes in the fair value of derivatives in current earnings, unless the derivative qualifies for cash flow hedge accounting treatment. The Company's derivative transactions are not designated as cash flow hedges. Accordingly, these derivative contracts are marked-to-market and any changes in the estimated values of derivative contracts held at the balance sheet date are recognized in the consolidated statement of operations as unrealized gains or losses on derivative contracts.

***Income Taxes***

The properties contributed by SEP I were historically owned by a limited partnership that is not a taxable entity and does not directly pay federal income taxes. Their taxable income or loss, which may vary substantially from the net income or net loss reported in the consolidated statements of operations, is allocated to the limited and general partners of SEP I. With the transfer of the SEP I Assets to the Company on December 19, 2011, the SEP I Assets' operations became subject to federal and state income taxes. At the date of acquisition, the Company estimated that the aggregate net tax basis of the SEP I Assets exceeded the aggregate net book basis by $24.9 million, resulting in a deferred tax asset of $8.7 million, which was fully offset by a valuation allowance.

Effective December 19, 2011, the Company accounts for income taxes using the asset and liability method. Deferred tax assets and liabilities arise from the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary difference and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Valuation allowances are

**Note 2. Basis of Presentation and Summary of Significant Accounting Policies (Continued)**

established when necessary to reduce the deferred tax asset to the amount more likely than not to be recovered.

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

The Company applies significant judgment in evaluating its tax positions and estimating its provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact the Company's financial position, results of operations and cash flows. The Company does not have uncertain tax positions and, as such, did not record a liability during the year ended December 31, 2012 or 2011.

***Earnings per Share***

Shares issued to SEP I in exchange for the SEP I Assets have been retroactively reflected as outstanding for all periods presented. The shares of common stock issued in exchange for the Marquis Assets as well as the shares issued in the IPO were considered outstanding since the date of these transactions.

Basic net earnings (loss) per common share are computed using the two-class method. The two-class method is required for those entities that have participating securities. The two-class method is an earnings allocation formula that determines net earnings (loss) per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. The Company's restricted shares of common stock (see Note 7) are participating securities under Accounting Standards Codification ("ASC") 260, *"Earnings per Share,"* because they may participate in undistributed earnings with common stock. Participating securities do not have a contractual obligation to share in the Company's losses. Therefore, in periods of net loss, no portion of the loss is allocated to participating securities.

Diluted net earnings (loss) per common share reflect the dilutive effects of the participating securities using the two-class method or the treasury stock method, whichever is more dilutive. They also reflect the effects of the potential conversion of the Convertible Preferred Stock using the if-converted method, if the effect is dilutive.

***Recent Accounting Pronouncements***

In December 2011, FASB issued authoritative guidance requiring entities to disclose both gross and net information about financial instruments and transactions eligible for offset in the statement of financial position as well as financial instruments and transactions subject to agreements similar to master netting arrangements. The additional disclosures will enable users of the financial statements to evaluate the effect or potential effect of netting arrangements on an entity's financial position. In

**Note 2. Basis of Presentation and Summary of Significant Accounting Policies (Continued)**

January 2013, FASB issued further authoritative guidance clarifying the scope of these disclosure requirements to include bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that either have a right of offset or are subject to an enforceable master netting arrangement or similar agreements. These disclosure requirements are effective for interim and annual periods beginning after January 1, 2013, and will primarily impact our disclosures associated with our commodity derivative instruments. The Company does not expect this guidance to have a significant impact on its consolidated financial position, results of operations or cash flows.

**Note 3. Cash and Cash Equivalents**

As of December 31, 2012 and 2011, cash and cash equivalents consisted of the following (in thousands):

| | 2012 | 2011 |
|---|---|---|
| Cash at banks | $ 5,265 | $63,041 |
| Money market funds | 82 | — |
| Commercial paper(1) | 45,000 | — |
| Total cash and cash equivalents | $50,347 | $63,041 |

(1) These securities mature three months or less from date of purchase.

**Note 4. Investments**

At December 31, 2012, the Company held certain investments in marketable securities as a means of temporarily investing the proceeds from its Convertible Preferred Stock offering until the funds are needed for operating purposes. At the time of acquisition, the Company classified these securities as "available for sale" due primarily to the Company's potential liquidity requirements that could result in these securities being sold prior to maturity.

The Company's investments in available-for-sale securities as of December 31, 2012 consisted of the following (in thousands):

| | 2012 |
|---|---|
| Commercial paper | $ 7,500 |
| Corporate notes and bonds | 4,091 |
| Total available-for-sale securities | $11,591 |

These investments are reflected at their fair value, based on quoted market prices, with unrealized gains and losses recorded in accumulated other comprehensive income until the investments are sold, at which time the realized gains and losses are included in the results of operations. As of December 31, 2012, there were no gains or losses recorded in accumulated other comprehensive income due to the fact that the fair value of these investments approximated the costs paid for these securities. The contractual maturities for the securities held at December 31, 2012 are January 2013. The Company did not have similar investments during prior periods.

**Note 5. Long-Term Debt**

On November 16, 2012, the Company and its subsidiaries, SEP Holdings III and Marquis LLC (collectively referred to with the Company as the "Borrowers"), entered into a Credit Agreement (the "First Lien Credit Agreement"), dated as of November 15, 2012, among the Borrowers, as borrowers, Capital One, National Association, as administrative agent, sole lead arranger and sole book runner, and each of the other lenders party thereto. The First Lien Credit Agreement provides for a $250 million revolving credit facility which matures November 16, 2015 and is secured by a senior lien on substantially all of the assets of the Borrowers. Availability under the First Lien Credit Agreement is at all times subject to customary conditions and the then applicable borrowing base, which is initially $27.5 million and subject to periodic redeterminations. All borrowings under the First Lien Credit Agreement bear interest, at the option of the Borrowers, either at an alternate base rate or a eurodollar rate. The alternate base rate of interest is equal to the sum of (a) the greatest of (i) the Wall Street Journal prime rate, (ii) the federal funds effective rate plus ½ of 1% and (iii) the one-month LIBO Rate multiplied by the statutory reserve rate, plus 1% and (b) the applicable margin. The eurodollar rate of interest is equal to the sum of (x) the LIBO Rate for the applicable interest period multiplied by the statutory reserve rate and (y) the applicable margin. The applicable margin varies from 1.50% to 2.00% for alternate base rate borrowings and from 2.50% to 3.00% for eurodollar borrowings, depending on the utilization of the borrowing base. Furthermore, the Borrowers are required to pay a commitment fee on the unused committed amount at a rate varying from 0.375% to 0.75% per annum, depending on the utilization of the borrowing base.

Also on November 16, 2012, the Company entered into a Credit Agreement (the "Second Lien Credit Agreement "and, together with the First Lien Credit Agreement, the "Credit Agreements "), dated as of November 15, 2012, among the Borrowers, as borrowers, Macquarie Bank Limited, as administrative agent, sole lead arranger and sole book runner, and the other lenders party thereto. The Second Lien Credit Agreement provides for a $250 million term loan facility which matures May 16, 2016 and is secured by a lien on substantially all of the assets of the Borrowers that is junior to those liens under the First Lien Credit Agreement. The Second Lien Credit Agreement provides for an initial commitment of $50 million, subject to certain conditions, with the remaining commitments subject to the approval of the lenders and other conditions. All borrowings under the Second Lien Credit Agreement bear interest at a eurodollar rate equal to the sum of (a) the LIBO Rate for the applicable interest period and (b) the applicable margin of 8.5%.

The Credit Agreements contain affirmative and negative covenants as well as events of default (including provisions providing for cross- default between the Credit Agreements). Furthermore, the Credit Agreements contain financial covenants that require the Borrowers to satisfy certain specified financial ratios, including current assets to current liabilities, interest coverage, total leverage, senior debt leverage and adjusted present value (as such terms may be defined or described in the applicable Credit Agreement). Upon an event of default under a Credit Agreement, the administrative agent thereunder may, at its election or at the direction of lenders holding, as applicable, at least 66⅔% of (i) the maximum committed amounts (if no borrowings or letters of credit are outstanding) or (ii) the outstanding borrowings and letter of credit exposure (if borrowings or letters of credit are outstanding) thereunder, accelerate the amounts due under its Credit Agreement. The Credit Agreements will be guaranteed by any future restricted subsidiaries (as defined in the Credit Agreements) of the Borrowers. As of December 31, 2012, the Company was in compliance with the covenants of the Credit Agreements.

**Note 5. Long-Term Debt (Continued)**

As of December 31, 2012, the Company had not made any draws under either Credit Agreement. Under the terms of the Second Lien Credit Agreement, the lenders' $50 million commitment would have expired on January 31, 2013 unless drawn by such date. The Company drew the available $50 million on January 31, 2013 leaving it with $50 million of outstanding debt. There is no usage under its revolving credit facility.

On February 21, 2013, the Company's available borrowing base under its First Lien Credit Agreement was increased from $27.5 million to $95.0 million. The Company's Second Lien Credit Agreement remained unchanged.

In connection with a purchase and sale agreement entered into subsequent to December 31, 2012 to purchase oil and natural gas properties (see Note 14), the Company secured commitments for $325 million in debt financing and expects to access the capital markets in the near term, subject to market conditions and other factors. Availability of the debt financing is conditioned upon, and is intended to be available concurrently with, the closing of the acquisition and will be subject to the satisfaction of various customary closing conditions.

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

**Note 6. Stockholders' Equity**

*Common Stock Offering*—On December 19, 2011, the Company completed its IPO of 10.0 million shares of common stock, par value $0.01 per share, at a price to the public of $22.00 per share. The Company received net proceeds of approximately $203.3 million from the sale of the shares of common stock (net of expenses and underwriting discounts and commissions).

*Preferred Stock Offering*—On September 17, 2012, the Company completed a private placement of 3,000,000 shares of Convertible Preferred Stock, which were sold to a group of qualified institutional buyers pursuant to the Rule 144A exemption from registration under the Securities Act. The private placement included 500,000 shares of Convertible Preferred Stock issued pursuant to the exercise of the initial purchasers' option to cover over-allotments. The issue price of each share of the Convertible Preferred Stock was $50.00. The Company received net proceeds from the private placement of approximately $144.5 million, after deducting initial purchasers' discounts and commissions and offering costs payable by the Company of approximately $5.5 million.

Pursuant to the Certificate of Designations for the Convertible Preferred Stock (the "Certificate of Designations"), each share of Convertible Preferred Stock is convertible at any time at the option of the holder thereof at an initial conversion rate of 2.3250 shares of common stock per share of Convertible Preferred Stock (which is equal to an initial conversion price of approximately $21.51 per share of common stock) and is subject to specified adjustments. Based on the initial conversion price, approximately 6,975,000 shares of common stock would be issuable upon conversion of all of the outstanding shares of the Convertible Preferred Stock.

**Note 6. Stockholders' Equity (Continued)**

The annual dividend on each share of Convertible Preferred Stock is 4.875% on the liquidation preference of $50 per share and is payable quarterly, in arrears, on each January 1, April 1, July 1 and October 1, commencing on January 1, 2013, when, as and if declared by the Company's Board of Directors (the "Board"). No dividends were accrued or accumulated prior to September 17, 2012. The Company may, at its option, pay dividends in cash and, subject to certain conditions, common stock or any combination thereof. As of December 31, 2012, all dividends accumulated through that date had been paid.

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

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

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

The following table shows the computation of basic and diluted net earnings (loss) per share for the years ended December 31, 2012, 2011 and 2010 (in thousands, except per share amounts):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| **Net income (loss)** | $(16,295) | $ 1,968 | $ (2,758) |
| Less: | | | |
| Preferred stock dividends | (2,112) | — | — |
| Net income allocable to participating securities(1)(4) | — | — | — |
| **Net income (loss) attributable to common stockholders** | $(18,407) | $ 1,968 | $ (2,758) |
| Weighted average number of unrestricted outstanding common shares used to calculate basic net earnings (loss) per share(2) | 33,000 | 22,479 | 22,091 |
| Dilutive shares(3)(4) | — | — | — |
| Denominator for diluted earnings (loss) per common share | 33,000 | 22,479 | 22,091 |
| **Net income (loss) per common share—basic and diluted** | $ (0.56) | $ 0.09 | $ (0.12) |

(1) For the year ended December 31, 2012, no losses were allocated to participating restricted stock because such securities do not have a contractual obligation to share in the Company's losses.

**Note 6. Stockholders' Equity (Continued)**

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

(3) 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.

(4) The Company had no outstanding stock awards prior to its initial grants in January 2012.

**Note 7. Stock-Based Compensation**

At the Annual Meeting of Stockholders of the Company held on May 23, 2012, the Company's stockholders approved the Sanchez Energy Corporation Amended and Restated 2011 Long Term Incentive Plan (the "LTIP"). The Company's Board had previously approved the amendment of the Sanchez Energy Corporation 2011 Long Term Incentive Plan on April 16, 2012, subject to stockholder approval.

The Company's directors and consultants as well as employees of the Sanchez Group who provide services to the Company are eligible to participate in the LTIP. Awards to participants may be made in the form of restricted shares, phantom shares, share options, share appreciation rights and other share-based awards. The maximum number of shares that may be delivered pursuant to the LTIP is limited to 15% of the Company's 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 the Company of its common stock, unless the Company's Board determines to increase the maximum number of shares of common stock by a lesser amount. Shares withheld to satisfy tax withholding obligations are not considered to be delivered under the LTIP. In addition, if an award is forfeited, canceled, exercised, paid or otherwise terminates or expires without the delivery of shares, the shares subject to such award are then available for new awards under the LTIP. Shares delivered pursuant to awards under the LTIP may be newly issued shares, shares acquired by the Company in the open market, shares acquired by the Company from any other person, or any combination of the foregoing.

The LTIP is administered by the Company's Board. The Company's Board may terminate or amend the LTIP at any time with respect to any shares for which a grant has not yet been made. The Company's Board has the right to alter or amend the LTIP or any part of the LTIP from time to time, including increasing the number of shares that may be granted, subject to shareholder approval as may be required by the exchange upon which the common shares are listed at that time, if any. No change may be made in any outstanding grant that would materially reduce the benefits of the participant without the consent of the participant. The LTIP will expire upon its termination by the Company's Board or, if earlier, when no shares remain available under the LTIP for awards. Upon termination of the LTIP, awards then outstanding will continue pursuant to the terms of their grants.

**Note 7. Stock-Based Compensation (Continued)**

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

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

During the year ended December 31, 2012, the Company issued 25,800 shares of restricted common stock pursuant to the LTIP to three directors of the Company that vest one year from the date of grant. Pursuant to ASC 718, stock based compensation expense for these awards was based on their grant date fair value of $17.57, $23.91 and $18.40 per share (the closing sales price of the Company's common stock on the grant date) and is being amortized over the one year vesting period.

The Company also issued approximately 1.8 million shares of restricted common stock pursuant to the LTIP to certain employees of SOG (including the Company's officers), with whom the Company has a services agreement. Approximately 1.1 million shares of restricted common stock were to vest equally over a two-year period and approximately 0.7 million shares of restricted common stock vest in equal annual amounts over a three-year period. On June 15, 2012, at the recommendation of the Company's President and Chief Executive Officer and with the consent of the recipients of these awards, the 1.1 million shares of restricted common stock that were to vest equally over a two-year period were rescinded and cancelled by the Board. All other grants previously made to employees of SOG were not modified or cancelled as a result of the rescissions.

For the restricted stock awards granted to non-employees that were rescinded and cancelled, stock-based compensation expense was based on the fair value at the date of cancellation, and all of the associated unrecognized compensation expense was accelerated and recognized as stock-based compensation expense. At the date of cancellation, the fair value of the stock awards cancelled was approximately $22.3 million, or $20.28 per restricted share.

**Note 7. Stock-Based Compensation (Continued)**

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

| | Year Ended December 31, 2012 | Year Ended December 31, 2011 |
|---|---|---|
| Restricted stock awards, directors | $ 288 | $— |
| Restricted stock awards, non-employees | 2,946 | — |
| Restricted stock awards, cancelled | 22,308 | — |
| **Total stock-based compensation expense** | $25,542 | $— |

Based on the $18.00 per share closing price of the Company's common stock on December 31, 2012, there was approximately $10.5 million of unrecognized compensation cost related to these non-vested restricted shares outstanding. The cost is expected to be recognized over an average period of approximately 2.37 years.

A summary of the status of the non-vested shares as of December 31, 2012 is presented below:

| | Number of Non-Vested Shares | Weighted Average Fair Value | Aggregate Intrinsic Value (in thousands) | Weighted Average Remaining Contractual Life (Years) |
|---|---|---|---|---|
| Non-vested restricted common stock at December 31, 2011 | — | $ — | $ — | |
| Granted | 1,874,300 | 17.82 | 33,396 | |
| Cancelled | (1,100,000) | 17.57 | (19,327) | |
| Forfeited | (11,900) | 17.57 | (209) | |
| Non-vested restricted common stock at December 31, 2012 | 762,400 | $18.18 | $ 13,860 | 2.37 |

As of December 31, 2012, approximately 4.2 million shares remain available for future issuance to participants.

**Note 8. Income Taxes**

The SEP I Assets contributed by SEP I were historically owned by a limited partnership that is not a taxable entity and is a disregarded entity for federal income tax purposes. SEP I's taxable income or loss was allocated to the limited and general partners of SEP I. With the transfer of the properties to the Company, the SEP I Assets' operations became subject to federal and state income taxes.

**Note 8. Income Taxes (Continued)**

The components of the federal income tax provision for the years ended December 31, 2012 and 2011 are (in thousands):

| | Year Ended December 31, 2012 | Year Ended December 31, 2011 |
|---|---|---|
| Deferred benefit recognized at date of acquisition | $ — | $(8,727) |
| Deferred expense (benefit) as a result of current operations | 2,105 | (106) |
| Income tax provision (benefit) | 2,105 | (8,833) |
| Increase (decrease) in valuation allowance | (2,105) | 8,833 |
| Net income tax provision | $ — | $ — |

The following table sets forth a reconciliation of the statutory federal income tax with the income tax provision (in thousands):

| | Year Ended December 31, 2012 | Year Ended December 31, 2011 |
|---|---|---|
| Income tax expense (benefit) at the federal statutory rate | $(5,703) | $ 689 |
| Income tax expense not provided on income prior to December 19, 2011 from oil and natural gas properties acquired | — | (795) |
| Basis difference on acquired oil and natural gas properties at date of transfer | — | (8,727) |
| Rescission of restricted stock | 7,808 | — |
| Income tax provision (benefit) | 2,105 | (8,833) |
| Valuation allowance | (2,105) | 8,833 |
| Net income tax provision | $ — | $ — |

The Company's deferred tax position reflects the net tax effects of the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts

**Note 8. Income Taxes (Continued)**

used for income tax reporting. Significant components of the deferred tax assets are as follows (in thousands):

| | As of December 31, 2012 | As of December 31, 2011 |
|---|---|---|
| Deferred tax assets: | | |
| Current: | | |
| Derivative obligations | $ 316 | $ 165 |
| Insurance | (117) | — |
| Share based compensation | 1,132 | — |
| Total current deferred tax assets | 1,331 | 165 |
| Noncurrent: | | |
| Net operating loss carryforwards | 45,253 | 778 |
| Asset retirement obligation | 6 | — |
| Depreciable, depletable property, plant and equipment | (39,763) | 7,890 |
| Total noncurrent deferred tax assets | 5,496 | 8,668 |
| Total deferred tax assets | 6,827 | 8,833 |
| Valuation allowance | (6,827) | (8,833) |
| Net deferred tax assets | $ — | $ — |

At December 31, 2012, the Company had net operating loss carryforwards of approximately $129.3 million which begin to expire in 2031.

In recording deferred income tax assets, the Company considers whether it is more likely than not that some portion or all of the deferred income tax assets will be realized. The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income during the periods in which those deferred income tax assets would be deductible. The Company believes that after considering all the available objective evidence, both positive and negative, historical and prospective, with greater weight given to historical evidence, there is insufficient evidence to determine that it is more likely than not that the deferred tax assets will be realized and therefore has established a full valuation allowance to reduce the net deferred tax asset to zero at December 31, 2012. The net change in valuation allowances during the years ended December 31, 2012 and 2011 was a decrease of $2.1 million and an increase of $8.9 million, respectively. The Company will continue to assess the valuation allowance against deferred tax assets considering all available information obtained in future reporting periods.

**Note 9. Related Party Transactions**

The Company does not have any employees. On December 19, 2011 it entered into a services agreement with SOG pursuant to which specified employees of SOG provide certain services with respect to the Company's business under the direction, supervision and control of SOG. Pursuant to this arrangement, SOG performs centralized corporate functions for the Company, such as general and administrative services, geological, geophysical and reserve engineering, lease and land administration, marketing, accounting, operational services, information technology services, compliance, insurance maintenance and management of outside professionals. The Company compensates SOG for the services at a price equal to SOG's cost of providing such services, including all direct costs and indirect administrative and overhead costs (including the allocable portion of salary, bonus, incentive compensation and other amounts paid to persons that provide the services on SOG's behalf) allocated in accordance with SOG's regular and consistent accounting practices, including for any such costs arising from amounts paid directly by other members of the Sanchez Group on SOG's behalf or borrowed by SOG from other members of the Sanchez Group, in each case, in connection with the performance by SOG of services on the Company's behalf. The Company also reimburses SOG for sales, use or other taxes, or other fees or assessments imposed by law in connection with the provision of services to the Company (other than income, franchise or margin taxes measured by SOG's net income or margin and other than any gross receipts or other privilege taxes imposed on SOG) and for any costs and expenses arising from or related to the engagement or retention of third party service providers.

The initial term of the services agreement is five years. The term will automatically extend for additional 12-month periods unless either party provides 180 days written notice otherwise prior to the expiration of the applicable 12-month period. Either party may terminate the agreement at any time upon 180 days written notice.

In connection with the services agreement, SOG also entered into a licensing agreement with the Company pursuant to which it granted to the Company a license to the unrestricted use of proprietary seismic, geological and geophysical information related to the Company's properties owned by SOG, and all such information related to the Company's properties not otherwise licensed to the Company will be interpreted and used by SOG for the Company's benefit under the services agreement. In addition, SOG entered into a contract operating agreement with the Company under which SOG agreed to develop, manage and operate the Company's properties or engage a responsible unaffiliated industry operator and joint owner for such development, management and operation. No costs, fees or other expenses are payable by the Company under these agreements. The licensing agreement and contract operating agreement will terminate concurrently with the termination or expiration of the services agreement.

Prior to entering into the services agreement, SOG incurred general and administrative expenses that were allocated to the Company based on the ratio of capital expenditures between the entities to which SOG provided services and the SEP I Assets. Other factors, such as time spent on general management services and producing property activities, were also considered in the allocation of these costs. Beginning December 19, 2011, the costs were allocated to the Company according to the terms of the services agreement. Salaries and associated benefit costs of SOG employees are allocated to the Company based on the actual time spent by the professional staff on the properties and business activities of the Company. General and administrative costs, such as office rent, utilities, supplies, and other overhead costs, are allocated to the Company based on a fixed percentage that is reviewed quarterly and adjusted, if needed, based on the activity levels of services provided to the Company.

**Note 9. Related Party Transactions (Continued)**

General and administrative costs that are specifically incurred by or for the specific benefit of the Company are charged directly to the Company. Expenses allocated to the Company for general and administrative expenses for the years ended December 31, 2012, 2011 and 2010 (in thousands) are as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| Administrative fees | $ 7,245 | $4,314 | $5,142 |
| Third-party expenses | 4,452 | 1,054 | 134 |
| Total included in general and administrative expenses | $11,697 | $5,368 | $5,276 |

During the fourth quarter of 2012, the Company paid $1.9 million as bonus payments to personnel employed by the Sanchez Group. These payments were included in general and administrative expenses as administrative fees.

As of December 31, 2012 and 2011, the Company had a payable to SOG of $13.5 million and $1.2 million, respectively, and a payable to SEP I of zero and $0.4 million, respectively. These amounts are reflected as "Accounts payable—affiliate" in the accompanying consolidated balance sheets.

**Note 10. Derivative Instruments**

To reduce the impact of fluctuations in oil and natural gas prices on the Company's revenues, or to protect the economics of property acquisitions, the Company periodically enters into derivative contracts with respect to a portion of its projected oil and natural gas production through various transactions that fix or, through options, modify the future prices to be realized. These transactions may include price swaps whereby the Company will receive a fixed price for its production and pay a variable market price to the contract counterparty. Additionally, the Company may enter into collars, whereby it receives the excess, if any, of the fixed floor over the floating rate or pays the excess, if any, of the floating rate over the fixed ceiling price. In addition, the Company enters into option transactions, such as puts or put spreads, as a way to manage its exposure to fluctuating prices. These hedging activities are intended to support oil and natural gas prices at targeted levels and to manage exposure to oil and natural gas price fluctuations. It is never the Company's intention to enter into derivative contracts for speculative trading purposes.

Under ASC Topic 815, "*Derivatives and Hedging,*" all derivative instruments are recorded on the consolidated balance sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. The Company will net derivative assets and liabilities for counterparties where it has a legal right of offset. Changes in the derivatives' fair values are recognized currently in earnings unless specific hedge accounting criteria are met. The Company has elected not to designate its current derivative contracts as hedges. Therefore, changes in the fair value of these instruments are recognized in earnings and included as realized and unrealized gains (losses) on derivative instruments in the consolidated statements of operations.

**Note 10. Derivative Instruments (Continued)**

As of December 31, 2012, the Company had oil derivative instruments covering anticipated future production as follows:

| Contract Period | Derivative Instrument | Barrels | Purchased | Sold |
|---|---|---|---|---|
| January 1, 2013 - December 31, 2013 | Put Spread | 365,000 | $95.00 | $75.00 |
| January 1, 2013 - December 31, 2013 | Swap | 182,500 | $97.10 | n/a |
| January 1, 2013 - December 31, 2013 | Swap | 365,000 | $88.90 | n/a |
| July 1, 2013 - December 31, 2013 | Put Spread | 184,000 | $90.00 | $75.00 |

The Company deferred the payment of premiums associated with certain of its oil derivative instruments. At December 31, 2012, the balance of deferred payments totaled approximately $1.0 million. These premiums will be paid to the counterparty with each monthly settlement.

*Balance Sheet Presentation*

The Company's derivatives are presented on a net basis as "Fair value of derivative instruments" on the consolidated balance sheets. The following information summarizes the fair value of derivative instruments as December 31, 2012 and 2011 (in thousands):

| | As of December 31, | |
|---|---|---|
| | 2012 | 2011 |
| Current asset | $2,145 | $1,461 |
| Long-term asset | — | — |
| Total fair value at period end | $2,145 | $1,461 |

*Gain (Loss) on Derivatives*

Gains and losses on derivatives are reported on the consolidated statements of operations as "Realized and unrealized gains (losses) on derivative instruments." Realized gains (losses) represent amounts related to the settlement of derivative instruments or the expiration of contracts. Unrealized gains (losses) represent the change in fair value of the derivative instruments to be settled in the future and are non-cash items which fluctuate in value as commodity prices change. The following summarizes the Company's realized and unrealized gains (losses) on derivative instruments for the years ended December 31, 2012 and 2011 (in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2012 | 2011 |
| Realized losses on derivative instruments | $(310) | $ — |
| Unrealized losses on derivative instruments | (432) | (480) |
| Total realized and unrealized losses on derivative instruments | $(742) | $(480) |

The Company had no derivative instruments during 2010.

**Note 11. Fair Value of Financial Instruments**

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

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

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

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

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

## Note 11. Fair Value of Financial Instruments (Continued)

*Fair Value on a Recurring Basis*

The following tables set forth, by level within the fair value hierarchy, the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2012 and 2011 (in thousands):

| | As of December 31, 2012 | | | |
|---|---|---|---|---|
| | Active Market for Identical Assets (Level 1) | Observable Inputs (Level 2) | Unobservable Inputs (Level 3) | Total Carrying Value |
| **Cash and cash equivalents:** | | | | |
| Commercial paper | $— | $45,000 | $ — | $45,000 |
| Money market funds | 82 | — | — | 82 |
| **Available-for-sale investments:** | | | | |
| Commercial paper | — | 7,500 | — | 7,500 |
| Corporate notes and bonds | — | 4,091 | — | 4,091 |
| **Oil derivative instruments:** | | | | |
| Swaps | | (870) | | (870) |
| Puts | — | — | 3,015 | 3,015 |
| Total | $82 | $55,721 | $3,015 | $58,818 |

| | As of December 31, 2011 | | | |
|---|---|---|---|---|
| | Active Market for Identical Assets (Level 1) | Observable Inputs (Level 2) | Unobservable Inputs (Level 3) | Total Carrying Value |
| **Description** | | | | |
| Oil derivative instruments—puts | $— | $— | $1,461 | $1,461 |
| Total | $— | $— | $1,461 | $1,461 |

The Level 1 instruments presented in the table above consist of money market funds included in cash and cash equivalents on the Company's Consolidated Balance Sheet at December 31, 2012. The Company's money market funds represent cash equivalents backed by the assets of high-quality banks and financial institutions. The Company identified the money market funds as Level 1 instruments due to the fact that the money market funds have daily liquidity, quoted prices for the underlying investments can be obtained and there are active markets for the underlying investments.

The Level 2 instruments presented in the table above consist of commercial paper and corporate notes and bonds included in cash and cash equivalents and available-for-sale investments on the Company's Consolidated Balance Sheet at December 31, 2012. The Company identified the commercial paper and corporate notes and bonds as Level 2 instruments due to the fact that although the assets do not have regular market pricing, their fair value can be readily determined based on other data values or market prices. These asset values can be closely approximated using simple models and extrapolation methods using known, observable prices as parameters.

**Note 11. Fair Value of Financial Instruments (Continued)**

The Company's oil derivative instruments, which consist of oil swaps and puts, are classified as either Level 2 or Level 3 in the table above. The fair value of the Company's derivatives is based on third-party pricing models which utilize inputs that are either readily available in the public market, such as oil forward curves, or can be corroborated from active markets of broker quotes. These values are then compared to the values given by the Company's counterparties for reasonableness. Since oil swaps do not include optionality and therefore generally have no unobservable inputs, they are classified as Level 2. The Company's oil puts include some level of unobservable input, such as volatility curves, and are therefore classified as Level 3. Derivative instruments are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of the Company's derivative instruments, but to date has not had a material impact on estimates of fair values. Significant changes in the quoted forward prices for commodities and changes in market volatility generally lead to corresponding changes in the fair value measurement of the Company's oil derivative instruments.

The fair values of the Company's oil derivative instruments classified as Level 3 at December 31, 2012 and 2011 were $3.0 million and $1.5 million, respectively. The significant unobservable inputs for Level 3 contracts include unpublished forward prices of oil, market volatility and credit risk of counterparties. Changes in these inputs will impact the fair value measurement of the Company's derivative contracts.

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

| | Significant Unobservable Inputs (Level 3) | |
|---|---|---|
| | Year Ended December 31, | |
| | 2012 | 2011 |
| Beginning balance | $ 1,461 | $ — |
| Realized and unrealized gains (losses) included in earnings | 128 | (480) |
| Settlements | (2,713) | — |
| Purchase of derivative contracts | 3,955 | 1,941 |
| Buy out of derivative contracts | 184 | — |
| Ending balance | $ 3,015 | $1,461 |
| Change in unrealized gains (losses) included in earnings related to derivatives still held as of December 31, 2012 and 2011 | $ 187 | $ (480) |

The Company had no derivative instruments during 2010.

***Fair Value on a Non-Recurring Basis***

The Company follows the provisions of ASC 820-10 for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. As it relates to the Company, the statement applies to the initial recognition of asset retirement obligations for which fair value is used.

**Note 11. Fair Value of Financial Instruments (Continued)**

The asset retirement obligation estimates are derived from historical costs as well as management's expectation of future cost environments. As there is no corroborating market activity to support the assumptions, the Company has designated these liabilities as Level 3. A reconciliation of the beginning and ending balances of the Company's asset retirement obligations is presented in Note 2.

**Note 12. Commitments and Contingencies**

From time to time, the Company may be involved in lawsuits that arise in the normal course of its business. It is the opinion of management and counsel that the outcome of any such lawsuits will not materially affect the financial position and operations of the Company.

**Note 13. Subsidiary Guarantors**

The Company has filed a registration statement on Form S-3 with the SEC, which became effective January 14, 2013 and registered, among other securities, debt securities. The subsidiaries of the Company (the "Subsidiaries") are co-registrants with the Company, and the registration statement registers guarantees of debt securities by the Subsidiaries. As of December 31, 2012, the Subsidiaries are 100 percent owned by the Company and any guarantees by the Subsidiaries will be full and unconditional (except for customary release provisions). The Company has no assets or operations independent of the Subsidiaries and there are no significant restrictions upon the ability of the Subsidiaries to distribute funds to the Company. In the event that more than one of the Subsidiaries provide guarantees of any debt securities issued by the Company, such guarantees will constitute joint and several obligations.

**Note 14. Subsequent Events**

Subsequent to December 31, 2012, the Company entered into two additional oil derivative contracts covering a portion of the Company's estimated 2014 production. In January 2013, the Company entered into a commodity derivative contract covering 1,500 bopd of oil production for all of calendar year 2014. The contract is a three-way costless collar consisting of a costless collar (long a $85 WTI put and short a $102.25 WTI call) plus a put (short a $65 WTI put). In February 2013, the Company entered into a commodity derivative contract covering an additional 1,000 bopd of oil production for all of calendar year 2014. The contract is a three-way costless collar consisting of a costless collar (long a $95 LLS put and short a $107.50 LLS call) plus a put (short a $75 LLS put).

On March 18, 2013, the Company executed a definitive agreement to purchase assets in the Eagle Ford Shale in South Texas from Hess Corporation, or 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. In connection with the proposed Hess acquisition, the Company secured commitments for $325 million in debt financing and expects to access the capital markets in the near term, subject to market conditions and other factors. Availability of the debt financing is conditioned upon, and is intended to be available concurrently with, the closing of the Hess acquisition and will be subject to the satisfaction of various customary closing conditions.

## Sanchez Energy Corporation

### Supplemental Quarterly Financial Results (Unaudited)

The following table presents the Company's unaudited quarterly financial information for 2012 and 2011 (in thousands, except per share amounts):

| | Fourth Quarter | Third Quarter | Second Quarter | First Quarter |
|---|---|---|---|---|
| **2012:** | | | | |
| Oil and natural gas revenue | $ 16,696 | $12,493 | $ 6,321 | $ 7,648 |
| Operating costs and expenses | (14,360) | (8,647) | (26,012) | (9,667) |
| Operating income (loss) | 2,336 | 3,846 | (19,691) | (2,019) |
| Other income (expense), net | (1,607) | (2,179) | 4,044 | (1,025) |
| Net income (loss) | 729 | 1,667 | (15,647) | (3,044) |
| Less: | | | | |
| Preferred stock dividends | (1,848) | (264) | — | — |
| Net income allocable to participating securities(1) | — | (21) | — | — |
| **Net income (loss) attributable to common stockholders** | $ (1,119) | $ 1,382 | $(15,647) | $(3,044) |
| Basic and diluted income (loss) per share(2) | $ (0.03) | $ 0.04 | $ (0.47) | $ (0.09) |
| Weighted average common shares outstanding—basic and diluted | 33,000 | 33,000 | 33,000 | 33,000 |
| **2011:** | | | | |
| Oil and natural gas revenue | $ 4,647 | $ 2,693 | $ 3,892 | $ 3,284 |
| Operating costs and expenses | (4,050) | (2,378) | (2,933) | (2,717) |
| Operating income | 597 | 315 | 959 | 567 |
| Other income (expense), net | (2,029) | 1,760 | (201) | — |
| Net income (loss) | $ (1,432) | $ 2,075 | $ 758 | $ 567 |
| Basic and diluted income (loss) per share(1) | $ (0.06) | $ 0.09 | $ 0.03 | $ 0.03 |
| Weighted average shares outstanding—basic and diluted | 23,632 | 22,091 | 22,091 | 22,091 |

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

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

## Sanchez Energy Corporation

## Supplementary Information on Oil and Natural Gas Exploration, Development and Production Activities

## (Unaudited)

The Company's oil and natural gas properties are located within the United States of America, which constitutes one cost center.

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

| | As of December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| Oil and Natural Gas Properties: | | | |
| Unproved | $138,937 | $126,201 | $20,823 |
| Proved | 232,523 | 31,836 | 5,674 |
| Total Oil and Natural Gas Properties | 371,460 | 158,037 | 26,497 |
| Less Accumulated depreciation, depletion, amortization and impairment | (22,605) | (6,703) | (2,457) |
| Net oil and natural gas properties capitalized | $348,855 | $151,334 | $24,040 |

***Costs Incurred***—Costs incurred in oil and natural gas property acquisition, exploration and development activities are summarized below for the period indicated (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| Unproved property acquisition costs | $ 9,371 | $111,224 | $ 8,964 |
| Exploration costs | 59,842 | 1,670 | 6,377 |
| Development costs | 144,208 | 20,234 | 2,880 |
| Total Costs Incurred | $213,421 | $133,128 | $18,221 |
| Seismic costs included in exploration costs | $ 2,676 | $ — | $ 249 |

***Results of Operations***—Results of operations for the Company's oil and natural gas producing activities are summarized below for the period indicated (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| Oil and natural gas revenue | $ 43,158 | $14,516 | $ 4,553 |
| Less operating expenses: | | | |
| Oil and natural gas production expenses | (3,401) | (1,628) | (391) |
| Production and ad valorem taxes | (2,124) | (830) | (214) |
| Depreciation, depletion, and amortization | (15,905) | (4,246) | (1,428) |
| Accretion expense | (17) | (6) | (2) |
| Results of operations from oil and gas producing activities | $ 21,711 | $ 7,806 | $ 2,518 |

***Reserves***—Proved reserves are those quantities of oil, NGL and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probalistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well.

Proved undeveloped reserves ("PUDs") are reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of producing economic quantities at a greater distance. Only those undrilled locations that are scheduled to be drilled within five years pursuant to a development plan can be allocated to undeveloped reserves, unless the specific circumstances justify a longer time. As of December 31, 2012, the Company did not have any PUDs previously disclosed that have remained undeveloped for five years or more and no PUD locations included in the Company's proved oil reserves are scheduled to be drilled after five years.

Estimates of proved developed and undeveloped reserves for the periods presented are based on estimates made by the independent engineers, Ryder Scott.

Proved reserves for all periods presented were estimated in accordance with the guidelines established by the SEC and FASB. The rules effective for fiscal years ended on or after December 31, 2009 require SEC reporting companies to prepare their reserve estimates based on the average prices during the 12-month period prior to the ending date of the period covered in the report, determined as the unweighted arithmetic average of the prices in effect on the first-day-of-the month for each month within such period, unless prices were defined by contractual arrangements. The product prices used to determine the future gross revenues for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from the market. The pricing used for the estimates of the Company's reserves of oil and condensate as of December 31, 2012, 2011 and 2010 was based on an unweighted twelve month West Texas Intermediate posted price of $94.71, $96.19 and $79.43, respectively. For natural gas the average price was based on an unweighted twelve month Henry Hub spot natural gas price average of $2.76, $4.12 and $4.38 as of December 31, 2012, 2011 and 2010, respectively.

## Sanchez Energy Corporation

## Supplementary Information on Oil and Natural Gas Exploration, Development and Production Activities

## (Unaudited)

***Net proved and proved developed reserve quantities summary***

The following table sets forth the net proved, proved developed and proved undeveloped reserves activity for the years ended December 31, 2010, 2011 and 2012.

| | Oil (mbo) | Natural Gas Liquids (mbbl) | Natural Gas (mmcf) | mboe(1) |
|---|---|---|---|---|
| Balance as of December 31, 2009 | 6 | — | 6 | 7 |
| Revisions of previous estimates | (1) | — | (6) | (2) |
| Extensions and discoveries(2) | 2,682 | — | 2,685 | 3,129 |
| Production | (56) | — | (32) | (61) |
| Balance as of December 31, 2010 | 2,631 | — | 2,653 | 3,073 |
| Revisions of previous estimates | (90) | 1 | 453 | (14) |
| Extensions and discoveries(2) | 3,215 | — | 3,476 | 3,795 |
| Production | (146) | (1) | (164) | (174) |
| Balance as of December 31, 2011 | 5,610 | — | 6,418 | 6,680 |
| Revisions of previous estimates | 1,022 | 1 | (245) | 981 |
| Extensions and discoveries | 12,052 | 310 | 9,916 | 14,015 |
| Production | (418) | (1) | (301) | (469) |
| Balance as of December 31, 2012 | 18,266 | 310 | 15,788 | 21,207 |
| Proved developed reserves: | | | | |
| As of December 31, 2010 | 362 | — | 1,541 | 619 |
| As of December 31, 2011 | 689 | — | 1,674 | 968 |
| As of December 31, 2012 | 3,211 | 99 | 2,433 | 3,716 |
| Proved undeveloped reserves: | | | | |
| As of December 31, 2010 | 2,269 | — | 1,112 | 2,454 |
| As of December 31, 2011 | 4,921 | — | 4,744 | 5,712 |
| As of December 31, 2012 | 15,055 | 211 | 13,355 | 17,491 |

(1) Oil equivalents are determined under the relative energy content method by using the ratio of 6.0 mcf of gas to 1.0 bo of oil.

(2) In early 2010, three successful wells were drilled in a large contiguous acreage block known as the Palmetto area which resulted in the initial booking of substantial proved undeveloped reserves at December 31, 2010. In 2011 and 2012, additional successful wells were drilled on the same acreage which resulted in the recording of additional undeveloped reserves at December 31, 2011 and 2012, respectivley.

## Sanchez Energy Corporation

## Supplementary Information on Oil and Natural Gas Exploration, Development and Production Activities

## (Unaudited) (Continued)

*Standardized Measure*—The standardized measure of discounted future net cash flows relating to the Company's ownership interest in proved oil, NGL and natural gas reserves as of December 31, 2012, 2011 and 2010 is shown below (in thousands):

| | As of December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| **Standardized Measure** | | | |
| Future cash inflows | $1,917,692 | $ 545,566 | $214,496 |
| Future production costs | (431,347) | (124,895) | (46,468) |
| Future development costs | (604,543) | (152,000) | (70,049) |
| Future income taxes(1) | (181,117) | (33,955) | — |
| Discount to present value at 10% annual rate | (414,385) | (101,558) | (47,268) |
| Standardized measure of discounted future net cash flows | $ 286,300 | $ 133,158 | $ 50,711 |

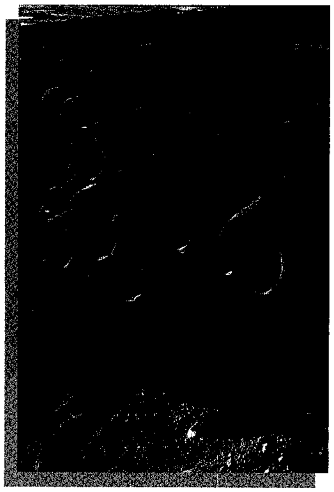
(1) Amounts as of December 31, 2010 do not include the effects of income taxes on future net revenues because the properties acquired were held by a limited partnership not subject to entity-level taxation.

The future cash flows are based on average first-day-of-month prices during the prior 12-month period and cost rates in existence at the time of the projections.

***Changes in standardized measure of discounted future net cash flows***—Changes in standardized measure of discounted future net cash flows relating to proved oil, NGL and natural gas reserves for each of the three years in the period ended December 31, 2012 are summarized below (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| **Summary of Changes** | | | |
| Balance, beginning of period | $ 133,158 | $ 50,711 | $ 197 |
| Changes in prices and costs | 22,700 | 9,512 | 44 |
| Revisions of previous quantity estimates | 35,055 | (401) | (30) |
| Extensions and discoveries | 401,353 | 135,574 | 88,538 |
| Sales of oil and gas—net of production costs | (37,633) | (12,058) | (3,948) |
| Net change in income taxes | (54,742) | (19,264) | — |
| Changes in development costs | (179,257) | (46,492) | (36,255) |
| Accretion of discount | 15,242 | 5,071 | 20 |
| Changes in rate of production | (42,642) | 4,874 | — |
| Other—net | (6,934) | 5,631 | 2,145 |
| Net change | 153,142 | 82,447 | 50,514 |
| Balance, end of period | $ 286,300 | $133,158 | $ 50,711 |

# CORPORATE INFORMATION



## Board of Directors

Antonio R. Sanchez, Jr.
Executive Chaiman of the Board

Antonio R. Sanchez, III
President and
Chief Executive Officer

Gilbert A. Garcia #
Managing Partner of
Garcia Hamilton & Associates

Greg Colvin #
Managing Partner, Chief Operating Officer and Head of Investor Relations of Sankofa Capital

Alan G. Jackson #
Senior Commercial Producer
IBC Insurance Agency, Ltd

# Member of the Audit committee

## Senior Management

Antonio R. Sanchez, Jr.
Executive Chaiman of the Board

Antonio R. Sanchez, III
President and
Chief Executive Officer

Joseph R. DeDominic
Senior Vice-President and
Chief Operating Officer

Michael G. Long
Senior Vice-President and
Chief Financial Officer

Kirsten A. Hink
Vice President and
Principal Accounting Officer

## Corporate Address

Sanchez Energy Corporation
1111 Bagby, Suite 1800
Houston, Texas 77002
Telephone: (713) 783-8000
Fax: (713) 756-2784
www.sanchezenergycorp.com

## Exploration Offices

1826 North Loop 1604 West
Suite 300
San Antonio, Texas 78248
Telephone: (210) 530-1239
Fax: (210) 530-8194

1920 Sandman
Laredo, Texas 78044
Telephone: (956) 722-8092
Fax: (956) 718-1057

## Transfer Agent and Registrar

Continental Stock Transfer
& Trust Company
17 Battery Place, 8th Floor
New York, NY 10004
Telephone: (212) 509-4000
Fax: (212) 509-5150

## Independent Auditors

BDO USA, LLP
Houston, Texas 77002

## Legal Counsel

Akin Gump Strauss Hauer & Feld LLP
Houston. Texas 77002

## Annual Meeting

The Company's Annual Meeting of Stockholders will be held at 9:00 A.M. CDT on May 22, 2013.

## Form 10-K

Copies of the Company's Annual Report on Form 10-K may be obtained, without charge, by writing to our Corporate Secretary at our Corporate Address or on the Company's website at www.sanchezenergycorp.com.

## Common stock Listing

Listed on NYSE as SN

SANCHEZ
ENERGY CORPORATION
WWW.SANCHEZENERGYCORP.COM