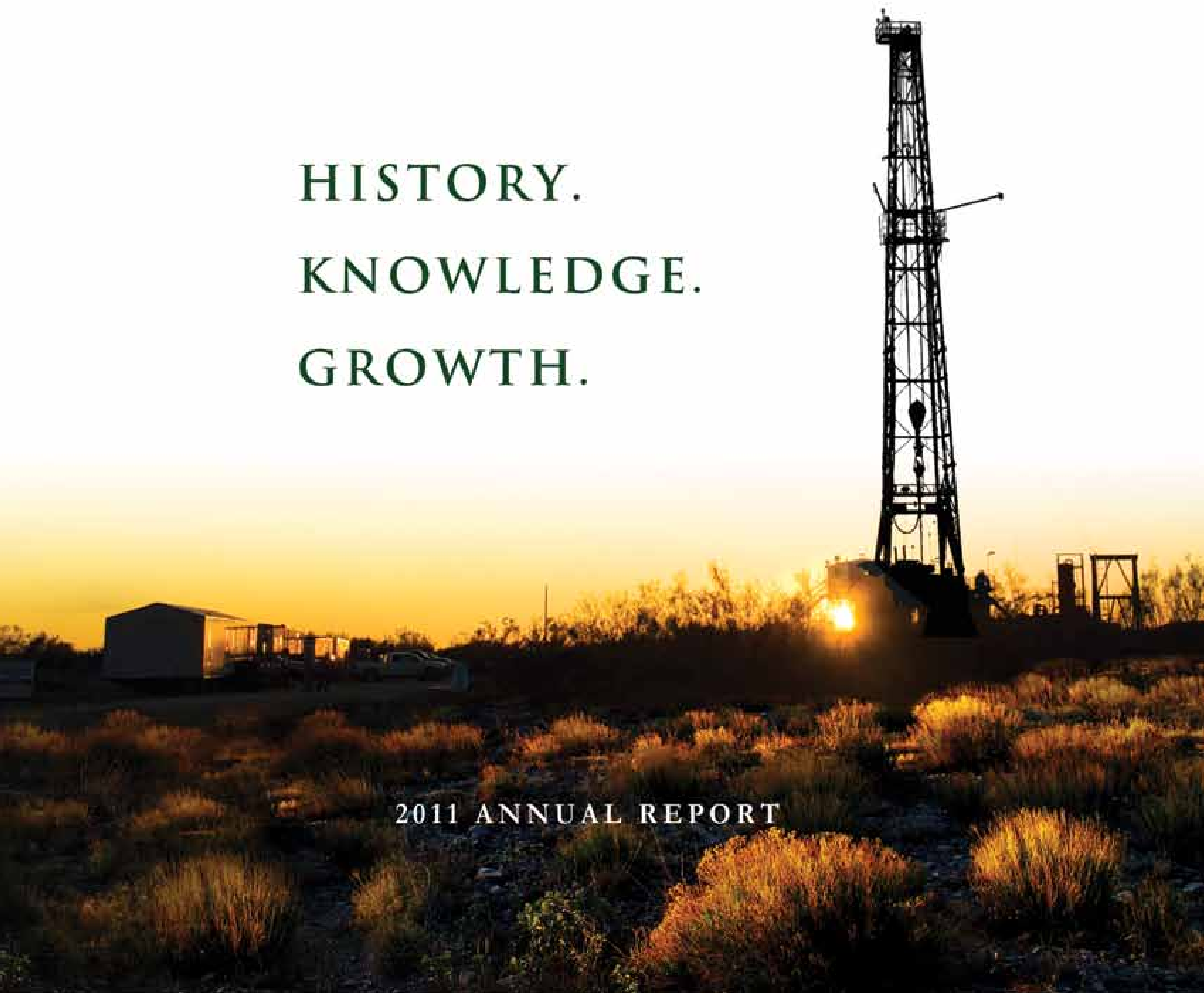
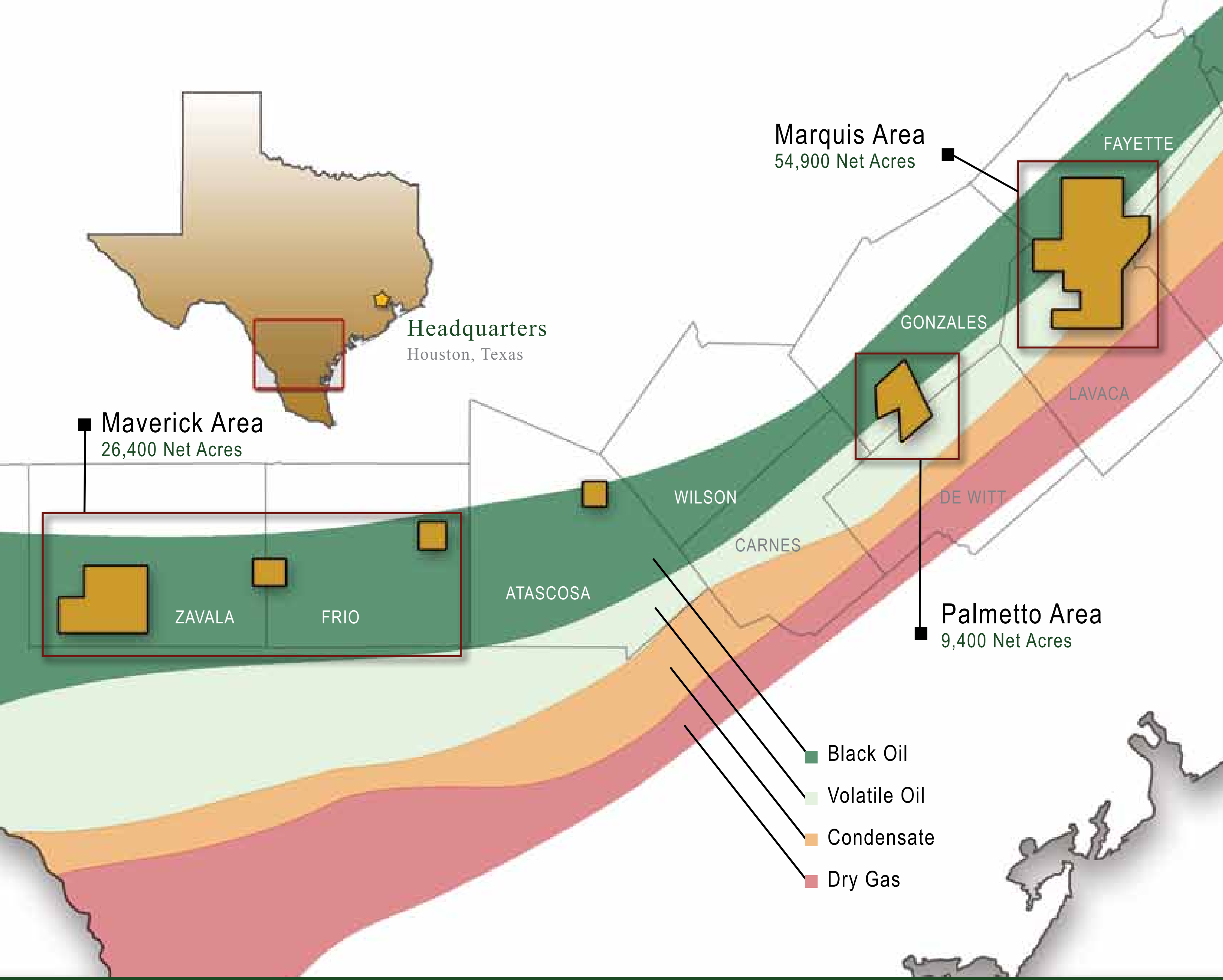
SANCHEZ
ENERGY CORPORATION

HISTORY.
KNOWLEDGE.
GROWTH.



2011 ANNUAL REPORT



CORPORATE PROFILE

Sanchez Energy Corporation is a high growth, publicly traded oil and natural gas producer pursuing significant low-risk drilling opportunities in the Eagle Ford Shale trend of South Texas, one of the world's premier shale plays. Our rapidly expanding presence is already significant in this prodigious trend, where a majority of our leases have full depth rights and are prospective for the Buda Limestone, Austin Chalk, and Pearsall shale formations in addition to the Eagle Ford.

TO OUR FELLOW SHAREHOLDERS:

INTRODUCTION

The previous 12 months was a time of great change and opportunity for Sanchez Energy Corporation. The goal of this inaugural annual report is to provide you, our shareholders, with information that will help you better understand the company's strategies, our strengths, and how we have positioned the company to excel as a newly minted public oil and natural gas company.

I only say new because on December 14, 2011, Sanchez began trading its common shares on the New York Stock Exchange. In actuality our roots run deep in Texas and in the oil and natural gas business.

My grandfather and father founded Sanchez Oil & Gas Corporation back in 1972. Sanchez Oil & Gas was built on the ideas that long-term value is built from hard work, a commitment to integrity, and a steeled resolve to overcome seeming impossibilities. Over the subsequent years and decades, it emerged as an active exploration and production company, drilling and participating in over 900 wells and developing strong relationships with the mineral owners of South Texas and other Gulf Coast basins.

> TODAY, THE COMPANY IS ONE OF THE LARGEST AND MOST RESPECTED OIL AND GAS OPERATORS IN TEXAS.

Sanchez Energy Corporation was created in 2011 to hold and develop the unconventional oil assets held by Sanchez Energy Partners I, an affiliate of Sanchez Oil & Gas Corporation. These unconventional assets consist primarily of our holdings in the Eagle Ford shale trend of South Texas. We became a public company on December 14, 2011, issuing 10 million shares at $22 per share. The IPO generated net proceeds of $203.3 million which, together with cash flow from operations and a liquid balance sheet, will fund an aggressive two-year, $350 million drilling program. Concurrent with the IPO, we closed on the acquisition of approximately 55,000 net acres in the Eagle Ford, bringing our total to 91,000 net acres, one of the largest and most concentrated positions in the trend.

VISION AND GOALS

Our goal is to increase the value of this company through a careful and thorough geologic and petro-physical evaluation process before making meaningful and concentrated investments in oil and natural gas leasehold with the objective of converting undeveloped acreage to production, reserves, and cash flow. Our strategies can be summarized as:

A. Focus our efforts on building a meaningful and concentrated resource base, which provides us with a scalable and substantial inventory of drilling locations targeting a multitude of geologic formations for years to come.

B. Increase our return on investment using our in-house geologic and engineering skills to reduce risk as we expand our resource base while tightly controlling costs.

C. Maintain a conservative financial structure and sufficient liquidity to ensure financial flexibility to aggressively develop our large inventory of drilling locations while at the same time being positioned to invest in and capture new opportunities through acquisitions of additional leasehold and/or producing properties.

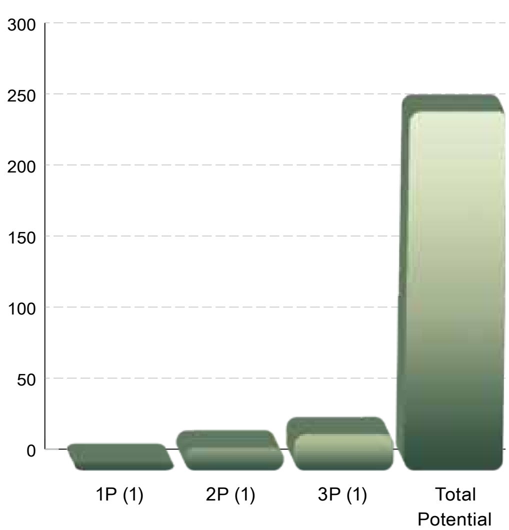
D. Hire, incentivize, and retain the best operating team and give them a significant financial stake in the success of the company.

EAGLE FORD SHALE

Our current drilling and growth focus is the Eagle Ford shale of South Texas. More specifically, we control over 91,000 net acres primarily located within the volatile oil and black oil windows of the trend. Our Eagle Ford holdings are divided into the following three areas:

- Palmetto (Gonzalez County): approximately 9,400 net acres (18,800 gross acres), where we have 50% working interest;
- Marquis (primarily Fayette and Lavaca Counties): approximately 55,000 net acres where we have 100% working interest; and
- Maverick (Zavala and Frio Counties): 26,400 net acres (33,100 gross acres) where we have an average 80% working interest.

Reserves and Potential (mmboe)



1. Per Ryder Scott as of 12/31/11. 3P reserves principally include the Palmetto area.

Each of these project areas is characterized by large contiguous blocks of acreage where we have high working interests and targets a different geologic section of the oil window of the trend. Our acreage position, based on 120-acre well spacing, has potential for over 750 well locations. Based on internal engineering assessments, we estimate our total year-end 2011 resource base at over 250 mmboe targeting the Eagle Ford.

> RECENT TESTING OF DRILLING WELLS ON TIGHTER SPACING, HAS SHOWN GOOD RESULTS.

Our internal analysis is based on having approximately 750 net Eagle Ford drilling locations, using 120-acre well spacing across our 91,000 net acreage position. More importantly, recent testing of wells on tighter spacing indicates the potential for increased ultimate recoveries per well. Early indications are that as completion procedures and technologies improve, and spacing between wells becomes tighter, per-well recoveries will increase due to an increased percentage recovery of the hydrocarbons in place. This means we will have more wells to drill and at the same time experience higher recovery levels on an individual well basis, thus driving higher net present values and internal rates of return per well.

The Energy Information Administration (EIA), part of the U.S. Department of Energy, estimates the Eagle Ford shale contains an undeveloped and technically recoverable resource of 10 billion barrels of oil equivalent. We believe the Eagle Ford will prove to be one of the largest oil discoveries ever found in the United States onshore and that our acreage position is ideally situated to exploit this great resource. We will remain focused on developing our acreage position as well as acquiring additional acreage which we view to be prospective and that we can purchase on the right terms and for an attractive price.

In addition to our holdings in the Eagle Ford, we control another 82,000 net acres in northern Montana and 1,200 acres in the Haynesville shale in Louisiana. The Montana acreage offers Sanchez the opportunity to drill and produce from the Bakken/Three Forks and Heath shales. We acquired this position in late 2008 and for less than $1 million can hold the leases through 2018, thus giving us plenty of time to evaluate the acreage. We like the optionality this acreage position holds for us. The EIA estimates Montana has more than 340 mmboe of crude oil plus condensate reserves yet to develop. The long-term optionality fits our strategy for developing additional oil focused resource plays.

THE EIA ESTIMATES MONTANA HAS MORE THAN 340 MMBOE OF CRUDE OIL PLUS LEASE CONDENSATE RESERVES YET TO DEVELOP.

Size is important; however, we are not a "land bank." We will own as much of a project's acreage that we believe is necessary to fully exploit an idea and provide a meaningful impact on our equity value. A million acres of pasture still has to be tended. We own a total of almost 175,000 acres. For now, our acreage in the Eagle Ford Shale represents essentially 100% of our production, reserve base and planned capital spending. We have ample time to explore, drill and exploit our other onshore unconventional oil and resources.

COMPANY AND PHILOSOPHY

Our technological and human resource asset base is meaningful and concentrated. Our oil and natural gas professionals have significant experience drilling and producing wells, and many of them have worked together with us for a multitude of years. Supporting this world class team is our 3-D geologic database that covers more than 6,400 square miles and 49,000 miles of 2D seismic data. We own 405,000 well logs, 13,000 LAS files used in our geologic interpretation work, and 32,000 scanned well documents, as well as a fully integrated suite of the latest interpretive geologic software. These tools provide us with the necessary platform to effectively run our current business plan and from which to analyze opportunities both in the Gulf Coast and other US basins.

Sanchez is a company that has historically been very aggressive in identifying and acquiring the right acreage at the right price. We believe that it is prudent to manage the inherent exploration and drilling risk through a thorough evaluation of the potential opportunity. In Palmetto, we developed a geologically well-defined strategy before beginning the land acquisition process. How did this benefit the company? Last year, our partner in Palmetto sold all of its Eagle Ford position including its 50% working interest in Palmetto to Marathon Oil for approximately $3.5 billion, or an average of $24,822 per net acre, one of the highest prices paid for Eagle Ford acreage. We originated the Palmetto area in 2008 before bringing in our original partner and paid about $350 per net acre for the initial 14,000 acre position. It is on this Palmetto position that we expect to focus a significant portion of our near-term drilling capital.

SANCHEZ IS A COMPANY THAT HAS HISTORICALLY BEEN VERY AGGRESSIVE IN IDENTIFYING AND ACQUIRING THE RIGHT ACREAGE AT THE RIGHT PRICE.

Results from our initial wells are some of the best in the industry, and our expectation is that as we embark on a continuous development program, cash flows and production will steadily ramp up at a high rate.

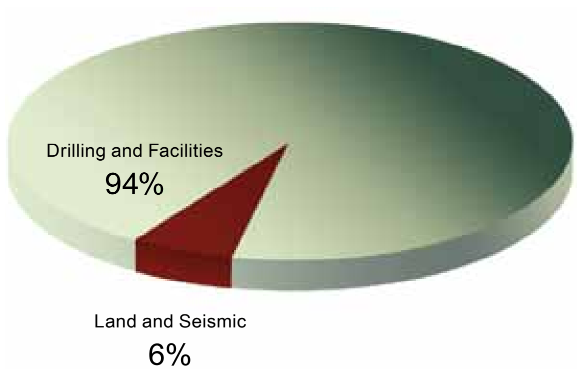
Newly public, Sanchez Energy Corporation is in the oil and natural gas business for the long term. Our commitment to our shareholders is to be creative in generating profitable opportunities in a wide range of market conditions. We will aggressively execute our drilling programs while prudently managing our capital resources. Debt is capital that you have to return. Equity is capital that generates trust and wealth. We plan to build on the trust that you have placed in us by being a shareholder.

We believe a company such as Sanchez Energy should maintain a conservative capital structure, with a cautious use of leverage. Before the impact of down-spacing, we have over 750 net Eagle Ford locations in our drilling inventory. Our procedure is to evaluate all of our opportunities – acquisition and drilling – to decide which ones meet our financial hurdle rates. Year after year for more than 40 years we have found that the people at Sanchez can generate more profitable opportunities than we can fund from internal cash flows. Our recent IPO was planned to address that capital need. We know we have to exceed your expectations with our operations and financial structure. If we are consistent in our processes and stick to our strategies we believe much will be achieved.

WE ARE PROUD
OF OUR PAST AND PROUDER
STILL OF THE PEOPLE
OF SANCHEZ

The past year was a starting point for the public company Sanchez Energy. We generated $14.5 million of revenue and net income of $2.0 million. We ended 2011 with 12 producing wells. Our two-year total spending program of approximately $400 to $425 million provides us with the opportunity to drill more than 46 net wells, fund central production facilities, continue to grow our leasehold position and add to our 3-D seismic coverage. We exited 2011 producing more than 1,300 barrels of oil equivalent per day (BOEPD); our target exit rate for 2012 is over 4,000 BOEPD. With no debt and the proceeds from our IPO, we believe we have the financial strength, capital liquidity, and one of the best operational teams in the business to aggressively convert our undeveloped reserve base and resource potential to production, proved reserves, and cash flow.

Two-Year Projected Capital Expenditures



We're proud of our past and prouder still of the people of Sanchez who will unlock the value we see in our company for our shareholders. They are the ones responsible for executing our strategies, finding and producing oil and natural gas and having the temerity and tenacity to cope with uncertainty and volatility. They are dedicated to our future success. As a shareholder and your chairman, I'm excited about being a part of this effort and reporting to you those future successes!

Best regards,

Antonio R. Sanchez, III
Chairman, President and Chief Executive Officer
March 30, 2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2011

OR

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

Commission file number: 1-35372

Sanchez Energy Corporation

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**45-3090102** (I.R.S. Employer Identification No.)
1111 Bagby Street, Suite 1600 **Houston, Texas** (Address of principal executive offices)	**77002** (Zip Code)

(713) 783-8000

(Registrant's telephone number, including area code)

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

(Title of Class)	(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 ☒

As of June 30, 2011, the last business day of the registrant's most recently completed second fiscal quarter, the registrant's common stock was not listed on any domestic exchange or over-the-counter market. The registrant's common stock began trading on the New York Stock Exchange on December 14, 2011. As of December 31, 2011, the aggregate market value of the registrant's common stock held by non-affiliates was approximately $188.3 million based on the closing price of the registrant's common stock on the New York Stock Exchange on December 30, 2011, the last trading day of the year on the New York Stock Exchange.

Number of shares of registrant's common stock outstanding as of March 27, 2012: 34,569,150.

Documents Incorporated By Reference:

Portions of the registrant's definitive proxy statement for its 2012 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2011, are incorporated by reference into Part III of this report for the year ended December 31, 2011.

SANCHEZ ENERGY CORPORATION
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2011

Table of Contents

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this Annual Report on Form 10-K, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report on Form 10-K, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "potential," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about our:

- business strategies;
- ability to replace the reserves we produce through drilling and property acquisitions;
- expected benefits of the acquisition of SN Marquis LLC, or Marquis LLC;
- drilling plans and locations;
- oil and natural gas reserves;
- technology;
- financial strategy, budget, projections and operating results;
- realized oil and natural gas prices;
- production volumes;
- oil and natural gas production expenses;
- general and administrative expenses;
- future operating results;
- cash flows and liquidity;
- availability of drilling and production equipment;
- availability of qualified personnel;
- capital expenditures;
- availability and terms of capital;
- drilling of wells;
- transportation and marketing of oil and natural gas;
- general economic conditions;
- competition in the oil and natural gas industry;
- effectiveness of our risk management activities;
- environmental liabilities;
- counterparty credit risk;

- governmental regulation and taxation;
- developments in oil-producing and natural-gas producing countries;
- estimated future net reserves and present value thereof; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

All forward-looking statements speak only as of the date of this Annual Report on Form 10-K. We disclaim any obligation to update or revise these statements except as required by law, and you should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Annual Report on Form 10-K are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under "Item 1A. Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Annual Report on Form 10-K. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

PART I

Item 1. *Business*

Overview

Sanchez Energy Corporation (together with our consolidated subsidiaries, 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, 2011, we had accumulated approximately 91,000 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 9,400 net acres in Gonzales County, Texas, which we refer to as our Palmetto area, approximately 26,400 net acres in Zavala and Frio Counties, Texas, which we refer to as our Maverick area, and approximately 54,900 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.

In addition, we have approximately 1,200 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 extend through 2012 and 2013, 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 estimated proved reserve information as of December 31, 2011 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, 2011 and our capital expenditure budget for the 2012 fiscal year:

	Net Acreage	Identified Drilling Locations(1) Gross	Identified Drilling Locations(1) Net	2012 Capital Expenditure Budget: Gross Wells	2012 Capital Expenditure Budget: Net Wells	2012 Capital Expenditure Budget: Drilling Capex (in millions)	Estimated Net Proved Reserves(2) (mmboe)
Palmetto—Gonzales(3)	9,416	157	75	13	6.5	$52 - $58	6.5
Maverick—Zavala, Frio	26,410	273	218	4	4.0	22 - 28	0.1
Marquis—Fayette, Lavaca, Atascosa, Webb and DeWitt	54,868	457	457	6	6.0	52 - 58	—
Total Eagle Ford Shale	90,694	887	750	23	16.5	126 - 144	6.6
Haynesville Shale	1,177	56	14	—	—	—	0.1
Heath, Three Forks and Bakken Shales	82,274	—	—	—	—	—	—
Total	174,145	943	764	23	16.5	$126 - $144	6.7

(1) Total identified drilling locations are calculated using approximately 120 acre spacing in our Eagle Ford Shale areas and approximately 80 acre spacing in our Haynesville Shale area on the

undeveloped portion of our acreage. We are currently evaluating our acreage in the Heath, Three Forks and Bakken Shales and have not identified any drilling locations on that acreage.

(2) Based on Ryder Scott estimated proved reserve report as of December 31, 2011.

(3) In our Palmetto area, we have 38 gross (19.5 net) locations that are classified as proved undeveloped at December 31, 2011. We plan to drill all of those proved undeveloped locations within the next five years.

Our Relationship with Sanchez Oil & Gas Corporation and Other Members of the Sanchez Group

Sanchez Oil & Gas Corporation, or SOG, headquartered in Houston, Texas, is a private full service oil and natural gas company engaged in the exploration and development of oil and natural gas primarily in the South Texas and onshore Gulf Coast areas on behalf of its affiliates. We refer to SOG, Sanchez Energy Partners I, LP, or SEP I, and their affiliates (but excluding us) collectively as the "Sanchez Group." Members of the Sanchez Group control the majority of the voting power of our outstanding common stock.

SOG, as it is known today, had its beginnings in 1972, when A. R. Sanchez, Sr., A. R. Sanchez, Jr. and a group of other partners from Houston and Laredo, Texas drilled their first well on the Hereford Ranch in Webb County, Texas. Since 1972, various members of the Sanchez Group have participated in and managed the drilling of over 900 wells, investing a substantial amount of capital in, among other things, well costs, seismic and acreage. SOG has approximately 83 permanent employees and numerous contract professionals. These individuals are experienced energy professionals with expertise in finance and operations and broad technical skills in the oil and natural gas business. In connection with the ongoing business of SOG, its employees review a large number of potential acquisitions and are involved in decisions relating to the acquisition and disposition of oil and natural gas assets by the various portfolio companies in which SOG owns interests, including SEP I. As discussed below, in connection with the closing of our initial public offering in December 2011, or the IPO, we entered into a services agreement, or the Services Agreement, and related agreements with SOG, pursuant to which we intend to leverage SOG's financial and technical expertise.

Although there is no obligation to do so, to the extent consistent with their fiduciary duties and other obligations to the investors and other parties associated with them, members of the Sanchez Group, including SOG, may refer to us or allow us to participate in new acquisitions by its portfolio companies and may cause its portfolio companies to contribute or sell oil and natural gas assets to us in transactions that would be beneficial to all parties. Given this potential alignment of interests and the overlapping ownership of the management of SOG, SEP I and other members of the Sanchez Group and us, we believe that we will benefit from the collective expertise of the employees of SOG, their extensive network of industry relationships, and the access to potential acquisition opportunities that would not otherwise be available to us. For a summary of the process by which such mutually agreeable prices will be determined, please read "Transactions with Related Persons" in the proxy statement for the 2012 annual meeting of stockholders, which is incorporated by reference to this report.

Our History

We were 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:

- SEP I 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, holding approximately 66.9% of our outstanding common stock immediately following the completion of our IPO and the related transactions.

- We acquired 100% of the limited liability company interests in Marquis LLC, which owns approximately 54,900 net acres 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, subject to adjustment, 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 the Services Agreement and other related agreements with SOG, pursuant to which 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 these agreements, please read Note 6 "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 and "Transactions with Related Persons" in the proxy statement for the 2012 annual meeting of stockholders, which is incorporated by reference to this report. SEP Holdings III and Marquis LLC each own interests in certain oil and natural gas and related assets.

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

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. The up to 887 gross (750 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 as we believe the Eagle Ford Shale to be the highest rate of return project that we currently possess. We anticipate drilling 23 gross (16.5 net) wells through December 2012 with an aggregate drilling and completion capital expenditure budget of approximately $126 to $144 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. We recently acquired approximately 54,900 net acres from Ross Exploration for approximately $89 million in cash, subject to adjustment, 909,091 shares of our common stock and an overriding royalty interest in what is now our Marquis area. 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.* Our largest stockholder is controlled by certain members of the Sanchez Group. 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 access to the unrestricted, 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 49,000 miles of 2D seismic data used for regional interpretation, 405,000 well logs, 13,000 LAS files and 32,000 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, 2011, we had approximately $63 million in cash and no outstanding indebtedness. We believe this strong liquidity position, combined with our cash flow from operations, will allow us to grow production and proved reserves, to capitalize on acreage acquisition opportunities and to weather any potential volatility in commodity prices. We currently expect that the net proceeds from the IPO, our expected cash flows from operations and any modest borrowings that we may make under a new credit facility that we anticipate entering into will be adequate to finance our planned capital expenditure program through December 2013.

Our Competitive Strengths

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

- *Geographically Concentrated Leasehold Position in One of North America's Leading Unconventional Oil Resource Trends.* We have assembled a current leasehold position of approximately 91,000 net leasehold acres in the Eagle Ford Shale, which we believe to be one of the highest rates of return unconventional oil and natural gas areas in North America. Our geographically concentrated acreage position allows us to establish economies of scale with respect to drilling, production, operating and administrative costs in addition to further leveraging our base of technical expertise in our project areas. We believe that offset operator activity and well results around our project areas have significantly de-risked our acreage positions such that we believe that there are low geologic risks and drilling opportunities across our acreage positions.

- *Large, Multi-Year Inventory.* We have an inventory of up to 887 gross (750 net) locations for potential future drilling on our Eagle Ford Shale acreage position and 56 gross (14 net) locations for potential future drilling on our Haynesville acreage position. Through December 2012, we plan on drilling 23 gross (16.5 net) wells on our Eagle Ford Shale acreage. The drilling and completion of these wells would represent approximately 3% of the total gross identified locations and approximately 2% of the total net identified locations on our Eagle Ford Shale acreage. As the industry continues to refine drilling and completion technologies, we may be able to enhance total recovery and inventory through the drilling of in-fill locations on our acreage positions. In addition, we have amassed approximately 82,000 net acres in Lewis and Clark, Meagher and Cascade Counties of Montana that we believe may be prospective for the Heath, Three Forks and Bakken Shales. If we are successful in developing this acreage, we could materially expand our multi-year inventory.

- *Our Relationship with Members of the Sanchez Group and Our Services Agreement Provide us with Extensive Technical Expertise and Access to Long Standing Relationships with Mineral Owners.* Certain members of the Sanchez Group have been in the oil and natural gas business since 1972 and have drilled or participated in over 900 wells, directly and through joint ventures, in and around our South Texas and onshore Gulf Coast areas. This long operating history in the basins in which we operate provides us with extensive knowledge of the basins and the ability to leverage longstanding relationships with mineral owners. We believe that this expertise and these relationships, together with our Services Agreement, should allow us to develop our assets efficiently and increase our acreage position.

- *Significant Financial Flexibility.* As of December 31, 2011, we had approximately $63 million in cash and no outstanding indebtedness. We are using this cash to fund our capital expenditures, and, in particular, our drilling, exploration and acquisition programs through December 2013, our other operating expenses, and for general corporate purposes. We currently expect that the net proceeds from the IPO, our expected cash flows from operations and any modest borrowings that we may make under a new credit facility that we anticipate entering into will be adequate to finance our planned capital expenditure program through December 2013.

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 804% from 27 rigs in January 2010 to 244 rigs as of December 30, 2011. 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.

The Eagle Ford Shale is a geological formation located in South Texas that lies directly beneath the Austin Chalk formation and above the Buda Limestone formation. It is considered to be the "source rock," or the original source of hydrocarbons that are contained in the Austin Chalk formation. The Eagle Ford Shale produces from various depths between 4,000 and 14,000 feet. The Eagle Ford Shale has a carbonate content as high as 70%, which makes it more similar to a traditional carbonate than to a shale. The high carbonate content and subsequently lower clay content make the Eagle Ford

Shale more brittle and easier to stimulate through hydraulic fracturing. The Eagle Ford Shale formation has an average organic content of 4.25% and has an average core-measured porosity of 9%.

In geological terms, the Eagle Ford Shale dips toward the Gulf of Mexico and is up to 300 feet thick in some areas, but averages 250 feet across the trend. Thermal maturity is impacted by the location and depth of the shale across the trend. Generally in shallower areas the Eagle Ford Shale is less thermally mature and therefore tends to be more oil prone. We refer to this area as the black oil window, and our Maverick area in Zavala and Frio Counties, Texas are situated within this window. The deeper, more thermally mature, areas of the Eagle Ford Shale are more gas prone. Areas in between, like our Palmetto area in Gonzales County, Texas tend to have a high natural gas liquids, or NGLs, content and are often referred to as the volatile oil window.

Most of the current Eagle Ford Shale activity is concentrated in Atascosa, Bee, DeWitt, Dimmit, Fayette, Frio, Gonzales, Karnes, LaSalle, Lavaca, Live Oak, Maverick, McMullen, Webb, Wilson and Zavala Counties in South Texas. The first horizontal wells drilled specifically for the Eagle Ford Shale were drilled in 2008, leading to a discovery in LaSalle County. Since then, the trend has expanded significantly across a large portion of South Texas.

Public information indicates that operators are typically drilling 3,500 to 7,000 feet horizontal laterals and applying hydraulic fracture stimulation in multiple stages along the full length of the horizontal laterals to complete the wells and establish production. Based on publicly available information, we believe that average drilling and completion costs in the trend have ranged between $5.5 million and $9.5 million per well with average estimated ultimate recoveries, or EURs, ranging from 225,000 to 850,000 boe per well, and initial 30-day average production has ranged between 200 to 2,000 boe/d per well. There have been a number of recent publicly-reported transactions in the trend that have yielded average per acre valuations ranging from approximately $5,000 per acre to $25,000 per acre. Based on our experience and that of other companies operating in this trend, we believe that the Eagle Ford Shale can be characterized as having low geologic risks and repeatable drilling opportunities.

In the Eagle Ford Shale, we have assembled approximately 91,000 net acres with an average working interest of approximately 84%. Using approximately 120 acre well-spacing for horizontal well development, we believe that there could be up to 887 gross and (750 net) locations for potential future drilling on our acreage. Consistent with other operators in this area, we plan to perform multi-stage hydraulic fracturing with 12 to 20 stages on each lateral well. Through December 2012, we plan to spend approximately $126 to $144 million on drilling 23 gross (16.5 net) wells on our Eagle Ford Shale acreage.

In our Palmetto area, we have approximately 9,400 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 $9.5 million per well based on publicly available information. We have participated in the drilling of six gross wells on our acreage that had an average initial 30-day per well choke restricted production rate of 951 boe/d (808 bopd and 853 mcf/d). In the second quarter of 2011, Hilcorp Energy Corporation closed its sale of 141,000 net acres in Gonzales, Atascosa and Karnes Counties in the Eagle Ford Shale to Marathon Oil Corporation, or Marathon, who is now our 50% working interest partner on our Palmetto acreage. Marathon has expressed to us a desire to accelerate drilling in our Palmetto area in 2012. We have identified up to 157 gross (75 net) locations based on 120 acre spacing for potential future drilling in our Palmetto area. Through December 2012, we plan to spend approximately $52 to $58 million to drill 13 gross (6.5 net) wells in our Palmetto area.

The following are the well results for our Palmetto area for wells that we drilled in 2011:

- In February 2011, we completed our fourth Eagle Ford horizontal well in our Palmetto area, the Barnhart #4H, in Gonzales County, Texas. This well was a 5,507 foot lateral well and was completed using a 16 stage hydraulic fracture stimulation. The 30-day average initial production rate from this well was 893 boe/d (713 bopd and 1,080 mcf/d) using a 15/64 inch restricted choke. Through December 31, 2011, the Barnhart #4H has produced a total of approximately 177,594 boe (133,990 bo and 261,625 mcf). We have a 50% working interest in the well.
- In December 2011, we completed our fifth and sixth Eagle Ford horizontal wells in our Palmetto area, the Barnhart #5H and #6H, in Gonzales County, Texas. The Barnhart #5H is a 5,991 foot lateral well and was completed using a 17 stage hydraulic fracture stimulation. The Barnhart #6H is a 5,998 foot lateral well and was completed using a 18 stage hydraulic fracture stimulation. The 30-day average initial production rates from the Barnhart #5H and #6H were 1,318 boe/d (1,137 bopd and 1,089 mcf/d) and 1,235 boe/d (1,056 bopd and 1,099 mcf/d), respectively, each using a 14/64 inch restricted choke. Through December 31, 2011, the Barnhart #5H had produced a total of approximately 37,041 boe (31,927 bo and 30,683 mcf) and the Barnhart #6H had produced a total of approximately 35,143 boe (29,953 bo and 31,140 mcf). We have a 50% working interest in the Barnhart #5H and a 50% working interest in the Barnhart #6H wells.

In our Maverick area, we have approximately 26,400 net operated acres in Zavala and Frio Counties, Texas with an average working interest of approximately 80%. 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 publicly available information. We have identified up to 273 gross (218 net) locations based on 120 acre spacing for potential future drilling on our Maverick acreage. We have drilled one vertical well to test the feasibility of a vertical development program and compare horizontal and vertical completion economic returns. Through December 2012, we plan to spend approximately $22 to $28 million to drill 4 gross (4 net) wells in our Maverick area.

In July 2011, we completed our first Maverick area Eagle Ford horizontal well, the Alpha Ware #1H, in Zavala County, Texas. This well was a 6,513 foot lateral well and was completed using a 20 stage hydraulic fracture stimulation. The 30-day average initial production rate from this well was 242 bopd. Through December 31, 2011, the Alpha Ware #1H has produced a total of approximately 20,970 bo. We are the operator of the well and have a 60% working interest in the well.

In our Marquis area, we have approximately 54,900 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 $6.5 million and $8.5 million per well based on publicly available information. We have identified up to 457 gross and net locations based on 120 acre spacing for potential future drilling on our Marquis acreage. Other operators in this project area have recently reported initial per well production rates of 1,000 to 1,200 boe/d. Through December 2012, we plan to spend approximately $52 to $58 million to drill 6 gross (6 net) wells in our Marquis area.

Haynesville Shale

The Haynesville Shale is a geologic formation located in northwest Louisiana and East Texas that lies below the Cotton Valley and Bossier formations and above the Smackover formation. The Haynesville Shale produces from various depths between 10,500 to 13,500 feet. Sub-surface, the formation dips southward toward the Gulf of Mexico and is found deeper the further south wells are drilled. The Haynesville Shale's porosity is often higher than other shales with an average core-measured porosity of 8.5%. The Haynesville Shale has a typical thickness ranging from 200 to 300 feet and an average organic content of 2.25%. The Haynesville Shale produces primarily dry natural gas with almost no associated liquids.

The trend has seen significant drilling activity over the last several years with the most activity focused in Bossier, Caddo, DeSoto, Natchitoches, and Red River Parishes in Louisiana and Harrison, Rusk, Panola and Shelby Counties in Texas. Operators are typically drilling 4,500 to 5,000 feet horizontal laterals and applying hydraulic fracture stimulation in multiple stages along the entire length of the horizontal laterals to complete the wells and establish production. Although production rates vary widely across the trend, in the core area of the trend, initial production rates of 20.0 to 25.0 mmcf per day of natural gas have been reported by operators.

We have assembled approximately 1,200 net acres in Natchitoches Parish, Louisiana that are prospective for the Haynesville Shale. We have an average working interest of approximately 25%, and the operator on our Haynesville Shale acreage is Chesapeake Energy Corporation. Three gross wells have been drilled to date, and we have participated in one of those wells. The one well (32% working interest) went on production in October 2011 and was tested on an initial choke restricted production rate of 9 mmcf/d. We believe that our acreage position is in the core of the Haynesville Shale fairway. We anticipate drilling, completion and facilities costs on our acreage to be between $8.0 and $10.0 million per well. We have identified 56 gross and 14 net locations for potential future drilling on our acreage. We do not currently anticipate spending any capital on our Haynesville Shale acreage in the near term. The majority of our Haynesville Shale leases extend through 2012 and 2013, giving us and our partners the option to accelerate drilling should natural gas prices increase.

Heath, Three Forks and Bakken Shales

We have acquired approximately 82,000 net acres in Lewis and Clark, Meagher, and Cascade Counties of Montana that we believe may be prospective for the Heath, Three Forks and Bakken Shales. We plan to monitor industry activity in our area as we develop our plans. Our lease terms are for five years with an option to renew for another five years at $10 per acre, giving us time to allow industry activity to develop the trend before we devote significant drilling capital to our acreage position.

Oil and Natural Gas Reserves and Production

Internal Controls

Our estimated reserves at December 31, 2011 were prepared by Ryder Scott, our independent reserve engineers. We expect 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, 2011, 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, 2011
Reserve Data(1):	
Estimated proved reserves:	
Oil (mbo)	5,610
Natural gas (mmcf)	6,418
Total estimated proved reserves (mboe)(2)	6,680
Estimated proved developed reserves:	
Oil (mbo)	689
Natural gas (mmcf)	1,674
Total estimated proved developed reserves (mboe)(2)	968
Estimated proved undeveloped reserves:	
Oil (mbo)	4,921
Natural gas (mmcf)	4,744
Total estimated proved undeveloped reserves (mboe)(2)	5,712
Standardized Measure (in millions)(3)	$133.2

(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 $96.19/bo for oil and $4.12/mmbtu for natural gas at December 31, 2011. 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, 2011, the average realized prices for oil and natural gas were $95.31 per bo and $3.66 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 and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil 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 and natural gas that are ultimately recovered. For a discussion of risks associated with internal reserve estimates, please read "Item 1A. Risk Factors—Risks Related to Our Business—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 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, 2011 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 and our cash flow from operations. 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 flow from operations and, if needed, through additional equity capital and any credit facility we may enter into. We currently expect that the net proceeds from the IPO, our expected cash flows from operations and any modest borrowings that we may make under a new credit facility that we anticipate entering into will be adequate to finance our planned capital expenditure program through December 2013. 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 SEP I's 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, 2011 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.

	At December 31, 2011(2)					
	Proved Reserves (mboe)(4)	**PV-10(5) (in millions)**	**Probable Reserves(3) (mboe)(4)**	**PV-10(5) (in millions)**	**Possible Reserves(3) (mboe)(4)**	**PV-10(5) (in millions)**
Project Area(1)						
Eagle Ford						
Palmetto—Gonzales	6,529	$149.9	7,771	$162.9	9,401	$106.1
Maverick—Zavala, Frio	46	1.8	1,408	21.8	—	—
Total Eagle Ford	6,575	$151.7	9,179	$184.7	9,401	$106.1
Haynesville	105	0.7	—	—	—	—
Total	6,680	$152.4	9,179	$184.7	9,401	$106.1

(1) Excludes our Marquis area, which had no estimated proved, probable or possible reserves at December 31, 2011.

(2) Our estimated net proved, probable and possible reserves and related PV-10 at December 31, 2011 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 $96.19/bo for oil and $4.12/mmbtu for natural gas at December 31, 2011. 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, 2011, the average realized prices for oil and natural gas were $95.31 per bo and $3.66 per mcf, respectively.

(3) In addition to the estimated proved reserve report dated December 31, 2011, Ryder Scott provided us with a probable and possible reserve report as of December 31, 2011 for the Palmetto and Maverick areas. Probable and possible reserves included in the report totaled 19 mmboe and $290.8 million in additional PV-10 value. Of these reserves, 92% were attributed to our Palmetto area and 8% were attributed to our Maverick area, and 8,103 mbo and 8,099 mbo were classified as oil, 6,455 mmcf and 7,809 mmcf were classified as natural gas and none 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.

(4) 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.

(5) 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, probable and possible 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, 2011 for our proved, probable and possible reserves.

	Proved Reserves	Probable Reserves	Possible Reserves
		(in millions)	
PV-10	$152.4	$184.7	$106.1
Present value of future income taxes discounted at 10%	(19.2)	(64.6)	(37.1)
Standardized Measure	$133.2	$120.1	$ 69.0

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,		
	2011	2010	2009
Production and operating data:			
Net production volumes:(1)			
Oil (mbo)	145.9	55.8	3.4
Natural gas (mmcf)	166.9	31.9	—
Total (mboe)	173.7	61.1	3.4
Average net production (boe/d)	475.9	167.4	9.2
Average sales price:(2)			
Oil (per bo)	$95.31	$78.92	$ 71.79
Natural gas (per mcf)	$ 3.66	$ 4.68	$ —
Average price per boe	$83.57	$74.50	$ 71.79
Average unit costs per boe:			
Oil and natural gas production expenses	$ 9.37	$ 6.41	$ 2.50
Production and ad valorem taxes	$ 4.78	$ 3.50	$ 3.31
General and administrative	$30.91	$86.32	$545.60
Depletion, depreciation and amortization	$24.44	$23.36	$123.65

(1) Our Palmetto area constituted approximately 97.7% of our estimated proved reserves as of December 31, 2011. Our production from the Palmetto area was 150.1 mboe for the year ended December 31, 2011 and 48.5 mboe for the year ended December 31, 2010. We

had no production in our Palmetto area in 2009. The 2011 production was comprised of 132.2 mbo of oil, 104.5 mmcf of natural gas and 466 bo of NGLs, and the 2010 production was comprised of 43.2 mbo of oil, 31.9 mmcf of natural gas and no NGLs.

(2) Prices do not include the effects of derivative cash settlements.

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,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	3.0	1.6	6.0	3.0	—	—
Dry	—	—	—	—	—	—
Exploratory wells:						
Productive	—	—	2.0	0.8	1.0	0.4
Dry	—	—	—	—	—	—
Total wells:						
Productive	3.0	1.6	8.0	3.8	1.0	0.4
Dry	—	—	—	—	—	—

The following table sets forth information at December 31, 2011 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	3.0	1.5	—	—
Non-operated	6.0	3.0	1.0	0.3
Total	9.0	4.5	1.0	0.3

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2011 relating to our leasehold acreage. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary. As of December 31, 2011, 3% of our acreage was held by production.

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Eagle Ford Shale—Palmetto	720	360	18,988	9,056
Eagle Ford Shale—Maverick	120	72	32,956	26,338
Eagle Ford Shale—Marquis	—	—	54,868	54,868
Haynesville	240	60	4,226	1,117
Heath, Three Forks and Bakken	—	—	82,274	82,274
Total	1,080	492	193,312	173,653

Excluding the properties in our Marquis area, as of December 31, 2011, we had leases representing 4,988 net acres (4,837 of which were in the Eagle Ford Shale) expiring in 2012, 21,259 net acres (21,214 of which were in the Eagle Ford Shale) expiring in 2013, and 175 net acres (175 of which were in the Eagle Ford Shale) expiring in 2014. The Marquis area includes approximately 54,900 net acres, none of which expires before December 31, 2013 except: (i) leases comprising 1,739 net acres covering properties in Webb County, Texas (with respect to each of which the lessee has an optional right to extend the primary term for a two-year period); (ii) properties comprising 695 net acres covering properties in DeWitt County, Texas; and (iii) properties comprising 461 net acres covering properties in Fayette County, Texas. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business, financial condition and results of operation.

Delivery Commitments

As of December 31, 2011, 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 less than 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, 2011, purchases by two of our customers accounted for 68% and 22%, respectively, of our total sales revenues. The two 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, EOG Resources, Inc., GeoResources, Inc., 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 competition for equipment, including drilling rigs and completion equipment. In recent years, the United States onshore oil and natural gas industry has experienced shortages of equipment, including drilling rigs and completion equipment, and personnel, which have delayed development drilling and other exploitation activities and caused significant increases in the prices for this equipment and personnel. We are unable to predict when, or if, such shortages 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 and past owner or operator of the site where the release occurred, 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 Driving 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, 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 federal Safe Drinking Water Act's, or SDWA, Underground Injection Control, or UIC, Program by posting a new requirement on its website that requires facilities to obtain permits to use diesel fuel in hydraulic fracturing operations.

The U.S. Energy Policy Act of 2005, which exempts hydraulic fracturing from regulation under the SDWA, prohibits the use of diesel fuel in the fracturing process without a UIC permit. Although the EPA has yet to take any action to enforce or implement this newly-asserted regulatory authority, industry groups have filed suit challenging the EPA's recent decisions as a "final agency action" and, thus, violative of the notice-and-comment rulemaking procedures of the Administrative Procedures Act. 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 late 2012, and a committee of the U.S. House of Representatives also is conducting an investigation of hydraulic fracturing practices. In addition, legislation was proposed in the recently ended 111th session of Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process, and such legislation could be introduced 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.

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 adopted a law in June 2011 requiring disclosure, by February 1, 2012, to the Railroad Commission of Texas and the public of certain information regarding the chemical components, as well as volume of water, used in the hydraulic fracturing process. Furthermore, on August 23, 2011, the EPA published in the Federal Register a proposed rule to establish new air emission controls for oil and natural gas production and natural gas processing operations. The new emissions standards seek to reduce volatile organic compound, or VOC, emissions, including a 95 percent reduction in VOCs emitted during the construction or modification of hydraulically-fractured wells. The EPA received public comment and conducted public hearings regarding the proposed rules and must take final action on them by April 3, 2012. If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws 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, in July 2011, pursuant to a court-ordered consent decree, the EPA proposed new emissions standards to reduce VOC emissions from several types of processes and equipment used in the oil and natural gas industry, including a 95 percent reduction in VOCs emitted during construction or modification of hydraulically-fractured wells. On August 23, 2011, the EPA published a proposed rule in the Federal Register that would establish these new air emission controls. The EPA received public comment and conducted public hearings regarding the proposed rules and must take final action on them by April 3, 2012. 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. The EPA has adopted two sets of regulations under the CAA. The motor vehicle rule, which became effective January 2011, purports to limit emissions of GHGs from motor vehicles manufactured in model years 2012-2016. A recent rulemaking proposal by the EPA and the Department of Transportation's National Highway Traffic Safety Administration seeks to expand the motor vehicle rule to include vehicles manufactured in model years 2017-2025. The EPA adopted the stationary source rule, or the tailoring rule, in May 2010, and it also became effective 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, in October 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including NGLs fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA published a final rule expanding 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 plans to implement GHG emissions standards for power plants in May 2012 and for refineries in November 2012.

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.

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 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 Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment to evaluate the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Currently, we have minimal exploration and production activities on federal lands. 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 the federal Occupational Safety and Health Act, as amended, or OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements.

Other Regulation of the Oil and Natural Gas Industry

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

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

As of December 31, 2011, we had no employees. In connection with the IPO, we entered into the Services Agreement with SOG pursuant to which SOG performs services for us, including the operation of our properties. Please read Note 6 "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 and "Transactions with Related Persons" in the proxy statement for the 2012 annual meeting of stockholders, which is incorporated by reference to this report. As of December 31, 2011, SOG had approximately 83 employees, including 7 engineers, 12 geoscientists and 6 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 1600, Houston, Texas 77002. SOG's lease expires in April 2013 and is currently being re-negotiated. 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 proceedings. In addition, we are not aware of any significant legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

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 oil and natural gas 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 and natural gas 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 and natural gas 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 and natural gas 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 and natural gas as we had estimated. 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 and natural gas 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 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 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. Additionally, on August 23, 2011, the EPA published a proposed rule in the Federal Register that would establish new air emission controls for oil and natural gas production and natural gas processing operations. The new emission standards seek to reduce VOC emissions, including a 95 percent reduction in VOCs emitted during the construction or modification of hydraulically-fractured wells. The EPA received public comment and conducted public hearings regarding the proposed rules and must take final action on them by April 3, 2012. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business. 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. Please read "Risks Related to our Business—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 generated from our operations or the issuance of debt and equity securities, or some combination thereof. 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 and natural gas reserves. We intend to finance our future growth and capital expenditures with cash flows from operations and the issuance of debt and equity securities, or some combination thereof.

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

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

If additional capital is needed to fund our growth capital expenditures, our ability to access the capital markets for future equity or debt offerings may be limited by our financial condition at the time of any such financing or offering, as well as by adverse market conditions resulting from, among other things, general economic conditions and contingencies and uncertainties that are beyond our control.

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

- domestic and foreign supply of and demand for oil and natural gas;
- weather conditions and the occurrence of natural disasters;
- overall domestic and global economic conditions;
- political and economic conditions in oil and natural gas 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 and other state-controlled oil companies relating to oil price and production controls;
- the effect of increasing liquefied natural gas deliveries to and exports from the United States;
- the impact of the U.S. dollar exchange rates on oil and natural gas 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 and natural gas pipelines and other transportation facilities;
- the availability of refining capacity; and
- the price and availability of alternative fuels.

In the past, oil and natural gas 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.

Our revenue, profitability and cash flow depend upon the prices of and demand for oil and natural gas, 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 and natural gas prices would reduce the amount of oil and natural gas 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 and natural gas 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 and natural gas production sometimes reflect a discount to 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 and natural gas 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.

In connection with the closing of the IPO, SEP I contributed to us a commodity derivative contract with a deferred premium cost of approximately $1.9 million, which we paid with a portion of the proceeds from the IPO. In the future, we expect to enter into commodity derivative contracts for a portion of our estimated production from total estimated proved developed producing reserves that could result in both realized and unrealized hedging losses. We also expect to adopt a hedging policy designed to reduce the impact to our cash flows from commodity price volatility. 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 and natural gas prices at the time we enter into these transactions, which may be substantially higher or lower than past or current oil and natural gas prices. Accordingly, our price hedging strategy may not protect us from significant declines in oil and natural gas 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 and natural gas prices that could have a significant adverse effect on our liquidity, business, financial condition and results of operation.

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

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

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

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices and activity levels in new regions, causing periodic shortages. During periods of high oil and natural gas 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 and natural gas 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 and natural gas 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 or natural gas 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. Excluding the properties in our Marquis area, as of December 31, 2011, we had leases representing 4,988 net acres (4,837 of which were in the Eagle Ford Shale) expiring in 2012, 21,259 acres (21,214 of which were in the Eagle Ford Shale) expiring in 2013, and 175 net acres (175 of which were in the Eagle Ford Shale) expiring in 2014. The Marquis area includes approximately 54,900 net acres, none of which expires before December 31, 2013 except: (i) leases comprising 1,739 net acres covering properties in Webb County, Texas (with respect to each of which the lessee has an optional right to extend the primary term for a two-year period); (ii) properties comprising 695 net acres covering properties in DeWitt County, Texas; and (iii) properties comprising 461 net acres covering properties in Fayette County, Texas. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business, financial condition and results of operation.

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

Our ability to bring oil, natural gas and NGLs production to market depends on a number of factors including the availability and proximity of pipelines and processing facilities. The recent growth in production in the Eagle Ford Shale, especially of natural gas and NGLs production, has limited the availability of transportation take-away capacity for these products in certain parts of this trend. If we 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.

We have drilled only eight wells in the Eagle Ford Shale, we are not the operator of our wells in the Haynesville Shale and we have not drilled wells in the Heath, Three Forks and Bakken Shales, and thus we have limited information regarding reserves and decline rates in the Eagle Ford Shale, Haynesville Shale, and the Heath, Three Forks and Bakken Shales. Wells drilled in these shale areas are more expensive and more susceptible to mechanical problems in drilling and completion techniques than wells in conventional areas.

We have drilled only eight wells in the Eagle Ford Shale, we are not the operator of our wells in the Haynesville Shale and we have not drilled wells in the Heath, Three Forks and Bakken Shales. Other operators in the Eagle Ford Shale, Haynesville Shale, and the Heath, Three Forks and Bakken Shales have significantly more experience in the drilling and completion of these wells, including the drilling and completion of horizontal wells. In addition, we have limited information with respect to the ultimate recoverable reserves and production decline rates in these areas. The wells drilled in the Eagle Ford Shale, Haynesville Shale, and the Heath, Three Forks and Bakken Shales are primarily horizontal and require more stimulation, which makes them more expensive to drill and complete. The wells will also be more susceptible to mechanical problems associated with the drilling and completion of the wells, such as casing collapse and lost equipment in the wellbore due to the length of the lateral portions of these unconventional wells. The fracturing of these shale formations will be more extensive and complicated than fracturing geological formations in conventional areas of operation.

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 and natural gas 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.

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 by posting a new requirement on its website that requires facilities to obtain permits to use diesel fuel in hydraulic fracturing operations.

The U.S. Energy Policy Act of 2005, which exempts hydraulic fracturing from regulation under the SDWA, prohibits the use of diesel fuel in the fracturing process without a UIC permit. Although the EPA has yet to take any action to enforce or implement this newly-asserted regulatory authority, industry groups have filed suit challenging the EPA's recent decisions as a "final agency action" and, thus, violative of the notice-and-comment rulemaking procedures of the Administrative Procedures Act. 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 late 2012, and a committee of the U.S. House of Representatives also has commenced its own investigation into hydraulic fracturing practices. Additionally, legislation was introduced in the 111th session of Congress to amend the SDWA to subject hydraulic fracturing processes to regulation under that Act and to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process, and such legislation could be introduced 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 adopted a law in June 2011 requiring disclosure, by February 1, 2012, to the Railroad Commission of Texas and the public of certain information regarding the chemical components, as well as volume of water, used in the hydraulic fracturing process. Furthermore, on August 23, 2011, the EPA published a proposed rule in the Federal Register that would establish new air emission controls for oil and natural gas production and natural gas processing operations. The new emissions standards seek to reduce VOC emissions, including a 95 percent reduction in VOCs emitted during the construction or modification of hydraulically-fractured wells. The EPA received public comment and conducted public hearings regarding the proposed rules and must take final action on them by April 3, 2012. If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws 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.

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.

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 and natural gas reserves and future production. It is not possible to measure underground accumulations of oil or natural gas in an exact way. Oil and natural gas reserve engineering is complex, requiring subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, future production levels and operating and development costs. In estimating our level of oil and natural gas 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 and natural gas 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, 2011 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 $25.7 million, from approximately $133.2 million to approximately $107.5 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 or natural gas 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 or natural gas 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 or natural gas will be present or, if present, whether oil or natural gas 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.

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 and natural gas 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 and natural gas 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 and natural gas 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 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, 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 and natural gas 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 and natural gas properties, including unproved and unevaluated property costs. Under full cost accounting rules, the net capitalized cost of oil and natural gas 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 and natural gas 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 and natural gas 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 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 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 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 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 recently completed 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 recently completed acquisitions of the SEP I Assets and the 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 acquisition of 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, and we may not seek an adjustment to the purchase price for any environmental liabilities. Ross Exploration will generally not be liable for any misrepresentation or breach of warranty unless asserted within one year of closing and the aggregate amount of damages with respect to such misrepresentation or breach of warranty exceeds $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 assets and operations can be adversely affected by weather and other natural phenomena.

Our assets and operations can be adversely affected by hurricanes, floods, earthquakes, tornadoes and other natural phenomena and weather conditions, including extreme temperatures. Insurance may be inadequate, and in some instances, we may not be able to obtain insurance on commercially reasonable terms, or insurance might not be available at all. A significant disruption in operations or a significant liability for which we were not fully insured could have a material adverse effect on our business, financial condition and results of operations.

Our customers' energy needs vary with weather conditions. To the extent weather conditions are affected by climate change or demand is impacted by regulations associated with climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes, leading either to increased investment or decreased revenues.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in some of the areas where we operate are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas on federal lands, drilling and other oil and natural gas activities can only be conducted during limited times of the year. This limits our ability to operate in those areas and can intensify competition during those times for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Our properties are located in regions which make us vulnerable to risks associated with operating in one major contiguous geographic area, including the risk and related costs of damage or business interruptions from hurricanes.

Our properties are primarily located in the Eagle Ford Shale in South Texas, and as a result of this geographic concentration, we are disproportionately affected by any delays or interruptions in production or transportation in these areas caused by governmental regulation, transportation capacity constraints, natural disasters, regional price fluctuations and other factors. Such disturbances have in the past and will in the future have any or all of the following adverse effects on our business:

- interruptions to our operations as we suspend production in advance of an approaching storm;
- damage to our facilities and equipment, including damage that disrupts or delays our production;
- disruption to the transportation systems we rely upon to deliver our products to our customers; and
- damage to or disruption of our customers' facilities that prevents us from taking delivery of our products.

Although we maintain property and casualty insurance, we cannot predict whether we will continue to be able to obtain insurance for hurricane-related damages or, if obtainable and carried, whether this insurance will be adequate to cover our losses. In addition, we expect any insurance of this nature to be subject to substantial deductibles and to provide for premium adjustments based on claims. Any future hurricane-related costs and work interruptions could adversely affect our business, financial condition and results of operations.

Our lack of diversification will increase the risk of an investment in us.

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.

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 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. 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 transition to 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.

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.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and production and processing of, oil and natural gas. 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.

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 emissions of carbon dioxide, methane, and other 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 restrict emissions of GHGs under existing provisions of the CAA. The EPA subsequently adopted two sets of regulations under the existing CAA, one that requires a reduction in emissions of GHGs from motor vehicles and another that requires certain stationary sources to obtain permits and employ technologies to reduce GHG emissions. The EPA published the motor vehicle final rule in May 2010 and it became effective January 2011 and applies to vehicles manufactured in model years 2012-2016. A recent rulemaking proposal by the EPA and the Department of Transportation's National Highway Traffic Safety Administration seeks to expand the motor vehicle rule to include vehicles manufactured in model years 2017-2025. The EPA adopted the tailoring rule in May 2010, and it also became effective 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, in October 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including NGLs fractionators and local natural gas/ distribution companies, beginning in 2011 for emissions occurring in 2010. Furthermore, in November 2010, the EPA published a final rule expanding its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. The final rule, which may be applicable to many of our facilities, 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 plans to implement GHG emissions standards for power plants in May 2012 and for refineries in November 2012.

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.

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

The operations of the third parties on whom we rely for gathering and transportation services are 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.

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative contracts to reduce the effect of commodity price, interest rate and other risks associated with our business.

The U.S. Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. In October 2011, the Commodities Futures Trading Commission, or CFTC, approved final rules that establish position limits for futures contracts on 28 physical commodities, including four energy commodities, and swaps, futures that are economically equivalent to those contracts. The rules provide an exemption for "bona fide hedging" transactions or positions, but this exemption is narrower than the exemption under existing CFTC position limit rules. The new limits generally will go into effect 60 days after the CFTC further defines the term "swap". The financial reform legislation may require us to comply with margin requirements and with certain clearing and trade-execution requirements, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative contracts to spin off some of their derivatives contracts to a separate entity, which may not be as creditworthy as the current counterparty. The regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our business, financial condition and results of operations.

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

Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and natural gas. The Clean Water Act imposes restrictions and strict controls regarding the discharge of produced waters and other oil and natural gas waste into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The Clean Water Act and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. Many state discharge regulations, and the Federal National Pollutant Discharge Elimination System general permits issued by the EPA, prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into coastal waters. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Indeed, on October 20, 2011, the EPA announced its intention to develop federal pre-treatment standards for wastewater discharges associated with hydraulic fracturing activities. If adopted, the new pretreatment rules will require coalbed methane and shale gas operations to pretreat wastewater before transferring it to treatment facilities. Proposed rules are expected in 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 Exchange Act 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.

As a new public company with listed equity securities, 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 will occupy a significant amount of time from our board of directors and management and will significantly increase our legal and financial compliance costs and make such compliance more time-consuming and costly. We will need 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 be 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.

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 2012 and his proposed American Jobs Act of 2011 contain 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.

Failure of our service providers or disruptions to our outsourcing relationships might negatively impact our ability to conduct our business.

We rely on SOG for certain services necessary for us to be able to conduct our business. 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.

Some studies indicate a high failure rate of outsourcing relationships. A deterioration in the timeliness or quality of the services performed by the outsourcing providers or a failure of all or part of these relationships could lead to loss of institutional knowledge and interruption of services necessary for us to be able to conduct our business. The expiration of such agreements or the transition of services between providers could lead to similar losses of institutional knowledge or disruptions.

Acts of terrorism could have a material adverse effect on our business, financial condition and results of operations.

Our assets and the assets of our customers and others may be targets of terrorist activities that could disrupt our business or cause significant harm to our operations, such as full or partial disruption to the ability to produce, process, transport or distribute oil, natural gas or NGLs. Acts of terrorism as well as events occurring in response to or in connection with acts of terrorism could cause environmental repercussions that could result in a significant decrease in revenues or significant reconstruction or remediation costs.

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

Even when properly used and interpreted, 2D and 3D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical and our overall drilling success rate or our drilling success rate for activities in a particular area could decline.

Risks Related to Our Relationships with Members of the Sanchez Group

As long as we are controlled by SEP I, your ability to influence the outcome of matters requiring stockholder approval is limited.

SEP I owns the majority of our outstanding common stock. As long as SEP I has voting control of our company, SEP I will have the ability to take many stockholder actions, including the election or removal of directors, irrespective of the vote of, and without prior notice to, any other stockholder. As a result, SEP I will have the ability to influence or control all matters affecting us, including:

- the composition of our board of directors and, through our board of directors, decision-making with respect to our business direction and policies, including the appointment and removal of our officers;
- any determinations with respect to acquisitions of businesses, mergers or other business combinations;
- our acquisition or disposition of assets; and

- our capital structure.

SEP I's interests may not be the same as, or may conflict with, the interests of our other stockholders. As a result, actions that SEP I takes with respect to us, as our controlling stockholder, may not be favorable to us. In addition, this voting control may discourage transactions involving a change of control of our company, including transactions in which the holders of our common stock might otherwise receive a premium for their shares over the then-current market price. Furthermore, SEP I is not prohibited from selling a controlling interest in our company to a third party without your approval or without providing for a purchase of your shares.

We may have potential business conflicts of interest with members of the Sanchez Group regarding our past and ongoing relationships, and because of SEP I's controlling ownership in us, 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;
- sales or distributions by SEP I of all or any portion of its ownership interest in us, which could be to one of our competitors; 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. While we are controlled by SEP I, SEP I may seek to cause us to amend these agreements on terms that may be less favorable to us than the original terms of the agreement.

Pursuant to the terms of our amended and restated certificate of incorporation, SEP I and its affiliates are not required to offer corporate opportunities to us, and our directors and officers may be permitted to offer certain corporate opportunities to SEP I or its affiliates 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:

- SEP I and its affiliates 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 SEP I or its affiliates engage or seek to engage merely because we engage in the same or similar lines of business;
- to the fullest extent permitted by law, SEP I and its affiliates will have no duty to communicate their knowledge of, or offer, any potential business opportunity, transaction, or other matter to us, and SEP I and its affiliates 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 (or its affiliates) 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 "Transactions with Related Persons" in the proxy statement for the 2012 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.

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

In connection with 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. 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.

Risks Relating to Our Common Stock

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 and foreign countries where we operate;
- 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 substantial portion of our total outstanding shares may be sold into the market. This could cause the market price of our common stock to drop significantly, even if our business is doing well.

All of the shares sold in our IPO are be freely tradable without restrictions or further registration under the federal securities laws, unless purchased by our "affiliates" as that term is defined in Rule 144 under the Securities Act. The remaining shares held by SEP I and Ross Exploration are restricted securities as defined in Rule 144 under the Securities Act. Restricted securities may be sold in the U.S. public market only if registered or if they qualify for an exemption from registration, including by reason of Rules 144 or 701 under the Securities Act. All of our restricted shares will be eligible for sale in the public market beginning in 2012, subject in certain circumstances to the volume, manner of sale and other limitations under Rule 144, and also to the lock-up agreements described under "Underwriting and Conflicts of Interest" in the prospectus relating to our IPO, or the prospectus. In addition, SEP I and its transferees have the right to require us to register the resale of their shares. See "Certain Relationships and Related Party Transactions—Agreements Governing the Transactions—Registration Rights Agreement" in the prospectus. Additionally, we have registered all 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 vesting conditions or transfer restrictions attached to them. Sales of a substantial number of shares of our common stock, or the perception in the market that the holders of a large number of shares intend to sell shares, could reduce the market price of our common stock.

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

Provisions in our amended and restated certificate of incorporation and amended and restated bylaws may delay or prevent an acquisition of us. These provisions may also frustrate or prevent any attempts by our stockholders to replace or remove our current management by making it more difficult for stockholders to replace members of our board of directors, who are responsible for appointing the members of our management team. Furthermore, because we are incorporated in Delaware, we are governed by the provisions of Section 203 of the Delaware General Corporation Law, which prohibits, with some exceptions, stockholders owning in excess of 15% of our outstanding voting stock from merging or combining with us. Finally, our amended and restated bylaws establish advance notice requirements for nominations for election to our board of directors and for proposing matters that can be acted upon at stockholder meetings. Although we believe these provisions together provide an opportunity to receive higher bids by requiring potential acquirers to negotiate with our board of directors, they would apply even if an offer to acquire us may be considered beneficial by some stockholders.

We are a "controlled company" within the meaning of the NYSE rules and, as a result, qualify for, and rely on, exemptions from certain corporate governance requirements that provide protection to stockholders of other companies.

SEP I owns more than 50% of the voting power of all outstanding shares of our capital stock entitled to vote generally in the election of directors, and we are a "controlled company" under the NYSE corporate governance standards. As a controlled company, we rely on certain exemptions from the NYSE standards that enable us to not have to comply with certain NYSE corporate governance requirements, including the requirements that:

- a majority of our board of directors consists of independent directors;
- we have a nominating and governance committee that is composed entirely of independent directors, with a written charter addressing the committee's purpose and responsibilities;
- we have a compensation committee that is composed entirely of independent directors, with a written charter addressing the committee's purpose and responsibilities; and
- we conduct an annual performance evaluation of the nominating and governance committee and compensation committee.

We rely on some or all of these exemptions, and, as a result, our stockholders do not have the same protection afforded to stockholders of companies that are subject to all of the NYSE corporate governance requirements.

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.

Holders. The number of shareholders of record of our common stock was approximately 3 on March 27, 2012, 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 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.

On March 27, 2012, the last sale price of our common stock, as reported on the NYSE, was $22.89 per share.

Securities Authorized for Issuance Under Equity Compensation Plans. The following table sets forth certain information as of December 31, 2011 regarding the Sanchez Energy Corporation 2011 Long Term Incentive Plan, or the 2011 Plan. The 2011 Plan was adopted by our board of directors prior to our IPO.

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available For Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity Compensation Plans Approved by Stockholders	N/A	N/A	N/A
Equity Compensation Plans Not Approved by Stockholders	—	N/A	3,960,000(1)
Total	—		3,960,000

(1) The maximum number of shares that may be delivered pursuant to the 2011 Plan is limited to 12% of our issued and outstanding shares of common stock. This maximum amount automatically increases to 12% 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. On December 19, 2011, in connection with the closing of our IPO and the related transactions, we issued 21,340,909 shares of common stock to SEP I and 909,091 to Ross Exploration. On January 12, 2012, following the expiration of the underwriters' over-allotment option, we issued 750,000 additional shares to SEP I. Each of these issuances was made for the acquisition of the SEP I Assets or the Marquis Assets, as the case may be, and was exempt from the registration requirements of the Securities Act by Section 4(2) thereof. Each offering and sale of our common stock was made only to SEP I or Ross Exploration, as applicable, each of which is an accredited investor, without advertising or general solicitation, and the transfer of the shares of common stock was restricted by us in accordance with the requirements of the Securities Act.

Use of Proceeds from the Sales of Registered Securities. In December 2011, we completed our IPO of common stock pursuant to a Registration Statement on Form S-1, as amended (File No. 333-176613) that was declared effective on December 13, 2011. Under the registration statement, we registered the offering and sale of an aggregate of 11,500,000 shares of our common stock (which included 1,500,000 shares of our common stock to be issued pursuant to the exercise of the underwriters' over-allotment option). The shares of common stock registered under the registration statement were sold at a price to the public of $22.00 per share. Johnson Rice & Company L.L.C. and Macquarie Capital (USA) Inc. acted as joint book-running managers for this offering and Johnson Rice & Company L.L.C. acted as representative of the underwriters. The offering commenced on December 2, 2011 and closed on December 19, 2011. As a result of the IPO, we raised a total of $220 million in gross proceeds, and approximately $203.3 million in net proceeds after deducting expenses and underwriting discounts and commissions of approximately $16.7 million.

We paid $50 million of the net proceeds from the offering to SEP I, an affiliate of ours, in partial payment for all of the limited liability company interests in SEP Holdings III and paid $89 million in partial payment for all of the limited liability company interests in Marquis LLC. We are using the remaining proceeds, after deducting payment for underwriting discounts and commissions and fees and expenses associated with the IPO and related transactions, to pay for drilling, exploration and acquisition expenditures and for general corporate purposes.

Repurchase of Equity Securities. Neither we nor any "affiliated purchaser" repurchased any of our equity securities in the quarter ended December 31, 2011.

Item 6. *Selected Financial Data*

The selected financial data as of December 31, 2011, 2010 and 2009 and for the years ended December 31, 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. Financial information is not presented for periods prior to 2008. Our properties did not have any production for periods prior to SEP I's acquisition of them and we believe that the omission of financial information for these periods is immaterial and unnecessary with respect to an understanding of our financial results and condition or any related trends and business prospects.

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 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.

	Years Ended December 31,			
	2011	2010	2009	2008
	(in thousands, except per share amounts)			
REVENUES:				
Oil sales	$13,905	$ 4,404	$ 241	$ —
Natural gas sales	611	149	—	—
Total revenues	14,516	4,553	241	—
COSTS AND EXPENSES:				
Oil and natural gas production expenses	1,628	391	9	—
Production and ad valorem taxes	830	214	11	—
Depreciation, depletion, amortization and accretion(1)	4,252	1,430	1,029	—
Gain on sale of oil and natural gas properties	—	—	(2,686)	—
General and administrative	5,368	5,276	1,833	1,247
Total operating costs and expenses	12,078	7,311	196	1,247
Operating income (loss)	2,438	(2,758)	45	(1,247)
Other income (expense):				
Interest and other income	10	—	—	—
Unrealized loss on derivatives	(480)	—	—	—
Net income (loss)	$ 1,968	$ (2,758)	$ 45	$ (1,247)
Net income (loss) per common share—basic and diluted	$ 0.09	$ (0.12)	$ —	$ (0.06)
Shares used to compute earnings (loss) per common share(2)	22,479	22,091	22,091	22,091

(1) Includes $0.6 million of full cost ceiling test impairment for the year ended December 31, 2009.

(2) Weighted average shares used to compute earnings (loss) per share for the years ended December 31, 2010, 2009 and 2008 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.

	As of December 31,			
	2011(1)	2010	2009	2008
	(in thousands)			
Balance Sheet Data:				
Working capital (deficit)	$ 63,890	$(1,818)	$ 59	$ (65)
Total assets	$217,356	$26,765	$13,275	$14,262
Total parent net investment / stockholders' equity	$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.

	Years Ended December 31,			
	2011	2010	2009	2008
	(in thousands)			
Cash Flow Data:				
Net cash provided by (used in) operating activities	$ 7,478	$(3,777)	$(1,710)	$ (1,247)
Net cash provided by (used in) investing activities	$(109,937)	$(7,925)	$ 2,734	$(14,197)
Net cash provided by (used in) financing activities	$ 165,500	$11,702	$(1,024)	$ 15,444

Other Financial Data

The following table presents a non-GAAP financial measure, Adjusted EBITDA, which we use in evaluating the financial performance and liquidity of our business. This measure is not calculated or presented in accordance with GAAP. We explain this measure below and reconcile it to the most directly comparable financial measures calculated and presented in accordance with GAAP.

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 settlement 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:
  - 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).

	Years Ended December 31,			
	2011	2010	2009	2008
	(in thousands)			
Net income (loss)	$1,968	$(2,758)	$ 45	$(1,247)
Plus:				
Unrealized loss on derivatives	480	—	—	—
Depreciation, depletion, amortization and accretion	4,252	1,430	415	—
Impairment of oil and natural gas properties	—	—	614	—
Less:				
Interest income	(1)	—	—	—
Gain on sale of oil and natural gas properties	—	—	(2,686)	—
Adjusted EBITDA	$6,699	$(1,328)	$(1,612)	$(1,247)

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

	Years Ended December 31,			
	2011	2010	2009	2008
	(in thousands)			
Net cash provided by (used in) operating activities	$7,478	$(3,777)	$(1,710)	$(1,247)
Net change in operating assets and liabilities	(779)	2,449	98	—
Adjusted EBITDA	$6,699	$(1,328)	$(1,612)	$(1,247)

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. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions, or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors which could cause actual results to vary from our expectations include: changes in oil and natural gas prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, particularly in "Risk Factors" and "Forward-Looking Statements," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Cautionary note regarding forward-looking statements."

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, 2011, we had accumulated approximately 91,000 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 estimated 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.

Basis of Presentation

SEP I is 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 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 SEP I Assets together with allocations of costs and expenses.

SEP Management I, LLC is the General Partner of SEP I and is a wholly owned subsidiary of SOG. SOG is a private oil and gas company engaged in the exploration for and development of oil and natural gas. SOG is the operator of a significant portion of SEP I's oil and natural gas properties. Pursuant to a management services agreement, SOG provides all employee, management, and administrative support to SEP I and, accordingly, through December 19, 2011, a proportionate share of SOG's general and administrative costs have been allocated to the Company. For purposes of the Company's financial statements, the costs of these services were allocated 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 are 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. Effective December 19, 2011, the Company and SOG entered into the Services Agreement pursuant to which SOG continues to provide these services to the Company, and the Company reimburses SOG for the costs it incurs in performing these services.

Our Properties

Our Eagle Ford Shale acreage is comprised of approximately 9,400 net acres in Gonzales County, Texas, which we refer to as our Palmetto area, approximately 26,400 net acres in Zavala and Frio Counties, Texas, which we refer to as our Maverick area, and approximately 54,900 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.

In addition, we have approximately 1,200 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 extend through 2012 and 2013, 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 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.

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, NGL 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 throughout 2009 and have remained low, relative to the prices in 2007 and 2008, due to a continued increase in natural gas supply and weak offsetting demand growth. The outlook for a worldwide economic recovery in 2012 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 2012. 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 and our access to capital.

Significant factors that may impact future commodity prices include the political and economic developments currently impacting Egypt, Libya and the Middle East in general; the extent to which members of the Organization of Petroleum Exporting Countries 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 SEP I and its affiliates, 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):

	Years Ended December 31,			Increase (Decrease)			
				2011 vs 2010		2010 vs 2009	
	2011	2010	2009	$	%	$	%
Net Production:							
Oil (mbo)	145.9	55.8	3.4	90.1	161%	52.4	1541%
Natural gas (mmcf)	166.9	31.9	—	135.0	423%	31.9	*
Total oil equivalent (mboe)	173.7	61.1	3.4	112.6	184%	57.7	1698%
Average Sales Price:							
Oil ($ per bo)	$ 95.31	$78.92	$71.79	$16.39	21%	$ 7.13	10%
Natural gas ($ per mcf)	$ 3.66	$ 4.68	$ —	$(1.02)	(22)%	$ 4.68	*
Oil equivalent ($ per boe)	$ 83.57	$74.50	$71.79	$ 9.07	12%	$ 2.71	4%
REVENUES:							
Oil sales	$13,905	$4,404	$ 241	$9,501	216%	$4,163	1727%
Natural gas sales	611	149	—	462	310%	149	*
Total revenues	$14,516	$4,553	$ 241	$9,963	219%	$4,312	1789%

* Not meaningful.

Net Production. Our total production for the year ended December 31, 2011 increased by 184% over the same period in 2010 to approximately 173.7 Mboe. Approximately 86% of our 2011 production was from the Palmetto area in Gonzales County with nine wells producing at year end compared to six wells at the end of 2010. In addition, we drilled one well in the Maverick area and one well in the Bodcaw area during 2011. Production for 2010 totaled 61.1 Mboe with eight wells producing at year end compared to production of 3.4 Mboe in 2009 with one well producing. In 2011, 84% of our production was oil and 16% was natural gas compared to 2010 production that was 91% oil and 9% natural gas. In 2009, 100% of our production was oil.

Average Sales Price. Our average realized oil price for the year ended December 31, 2011 increased 21% to $95.31 per bo as compared to $78.92 per bo and $71.79 per bo for the periods ended December 31, 2010 and 2009, respectively. The average price realized for our natural gas production in 2011 was $3.66 per Mcf, 22% lower than the average sales price in 2010 of $4.68 per Mcf. We did not have natural gas sales in 2009.

Revenues. Oil and natural gas sales revenues totaled approximately $14.5 million, $4.6 million and $0.2 million for the years ended December 31, 2011, 2010 and 2009, respectively. Oil sales revenue for the year ended December 31, 2011 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 compared to 2010. For the year ended December 31, 2010 compared to 2009, oil sales revenue increased $4.2 million with $3.8 million attributable to the increase in production and $0.4 million due to the higher average sales price. Natural gas sales revenue for the year ended December 31, 2011 increased approximately $462,000 with $632,000 attributable to the increase in production partially offset by $170,000 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):

	Years Ended December 31,			Increase (Decrease)			
				2011 vs 2010		2010 vs 2009	
	2011	2010	2009	$	%	$	%
OPERATING COSTS AND EXPENSES:							
Oil and natural gas production expenses	$ 1,628	$ 391	$ 9	1,237	316%	382	*
Production and ad valorem taxes	830	214	11	616	288%	203	*
Depreciation, depletion, amortization and accretion:							
Depreciation, depletion and amortization	4,246	1,428	415	2,818	197%	1,013	244%
Accretion expense	6	2	—	4	200%	2	*
Impairment of oil and natural gas properties	—	—	614	—	*	(614)	(100)%
Gain on sale of oil and natural gas properties	—	—	(2,686)	—	*	2,686	(100)%
General and administrative	5,368	5,276	1,833	92	2%	3,443	188%
Total operating costs and expenses	12,078	7,311	196	4,767	65%	7,115	*
Interest and other income	10	—	—	10	*	—	*
Unrealized loss on derivatives	(480)	—	—	(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 $1.2 million to approximately $1.6 million for the year ended December 31, 2011, as compared to $391,000 for the same period in 2010 and only $9,000 in 2009. The increase in oil and natural gas production expenses from 2009 to 2011 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 $830,000, $214,000 and $11,000 for the years ended December 31, 2011, 2010 and 2009, 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 realized prices 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 $0.4 million in 2009 to $1.4 million in 2010 and $4.2 million for the year ended December 31, 2011 due to increases in production.

Impairment of Proved Oil and Natural Gas Properties. If the net capitalized costs of our oil and natural gas properties exceed the estimated present value of future net cash flows from proved oil and natural gas reserves, discounted at 10%, such excess is charged to operations as a full cost ceiling impairment in that reporting period. We did not incur a full cost ceiling impairment for the years ended December 31, 2011 and 2010. For the year ended December 31, 2009, we incurred a full cost ceiling impairment of $614,000.

Gain on Sale of Unevaluated Oil and Natural Gas Properties. During December 2009, a portion of certain unevaluated oil and natural gas acreage was sold for approximately $5 million in cash. Because a reduction in the full cost pool by the net sales proceeds would have significantly altered the relationship between capitalized costs and proved reserves, the sale was considered significant and a $2.7 million gain was recorded in the statement of operations.

General and Administrative Expenses. Our general and administrative expenses increased 2% to approximately $5.4 million for the year ended December 31, 2011, as compared to the year ended December 31, 2010. Although we experienced a decrease in expense due to efforts undertaken in 2010 to reduce general and administrative expenses, these costs were offset by higher professional fees in late 2011. General and administrative expenses for the year ended December 31, 2010 totaled $5.3 million compared to $1.8 million for 2009. This increase was attributable to the increase in our activities from primarily leasing of undeveloped acreage to more emphasis on developing the acreage positions through increased drilling activities.

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, 2011, we had an unrealized loss on our derivative transactions of approximately $0.5 million. Because our outstanding contracts relate to 2012 production, no settlements were recognized in the current year. We had no derivative instruments during 2010 or 2009.

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

Additionally, we are 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, we 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.

We apply significant judgment in evaluating our tax positions and estimating our 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 our financial position, results of operations and cash flows. We do not have uncertain tax positions and, as such, did not record a liability during the year ended December 31, 2011 and 2010.

Liquidity and Capital Resources

As of December 31, 2011, we had approximately $63 million in cash and no indebtedness. We anticipate putting in place a new credit facility during 2012 to add to our liquidity and capital resources. We expect to use our cash, our internally generated cash flow and modest borrowings under our anticipated new credit facility to fund our planned capital expenditures, and, in particular, our drilling, exploration and acquisition programs through December 2013. The mid-point of our currently planned capital expenditure program for 2012 is $145 million, $135 million of which is anticipated to be used for the drilling and completion of 16.5 net wells with the remaining approximately $10 million to be spent on facilities, new leases and 3-D seismic. Our strategy is to fund our ongoing capital programs with the cash from our recent IPO, the cash flow generated from operations and modest amounts of indebtedness.

Cash Flows

Our cash flows for the years ended December 31, 2011, 2010 and 2009 are as follows:

	Years Ended December 31,		
	2011	2010	2009
	(in thousands)		
Cash Flow Data:			
Net cash provided by (used in) operating activities	$ 7,478	$ (3,777)	$(1,710)
Net cash provided by (used in) investing activities	$(109,937)	$ (7,925)	$ 2,734
Net cash provided by (used in) financing activities	$ 165,500	$11,702	$(1,024)

Net Cash Provided by (Used in) Operating Activities. Net cash provided by (used in) operating activities in 2011 was approximately $7.5 million compared to a use of funds in 2010 of $3.8 million and a use of funds in 2009 of $1.7 million. The increase in net cash provided by operating activities in 2011 was due primarily to higher revenue resulting from an increase in production as well as higher average oil sales prices as compared to 2010. The increase in net cash used in operating activities in 2010 compared to the same period in 2009 was largely due to the increase in general and administrative expenses in 2010 as our activity shifted from mainly leasing to a combination of leasing and drilling.

Net Cash Provided by (Used in) Investing Activities. Net cash flows used in investing activities totaled approximately $109.9 million for the year ended December 31, 2011 compared to $7.9 million for the same period in 2010. The increase was due primarily to our acquisition of the Marquis Assets, which used cash of $89.0 million. In addition, capital expenditures for leasehold and drilling activities increased from $13.8 million in 2010 to $20.6 million in 2011. Partially offsetting these costs were $1.6 million and $5.9 million in proceeds from the sale of certain non-core undeveloped leases for the year ended December 31, 2011 and 2010, respectively. Net cash provided by investing activities was approximately $2.7 million for the year ended December 31, 2009, which resulted from $5.8 million in proceeds from the sale of certain undeveloped leasehold acreage partially offset by $3.1 million in capital expenditures for leasehold and drilling activities.

Net Cash Provided by (Used in) Financing Activities. Net cash flows provided by financing activities totaled $165.5 million for the year ended December 31, 2011 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 estimated expenses and underwriting discounts and commissions). With proceeds from the IPO, we paid SEP I $50.0 million. Partially offsetting this payment were contributions by the parent of $12.2 million related to the operations from the oil and natural gas properties prior to the transaction date. For the years ended December 31, 2010 and 2009, all of our cash provided by financing activities resulted from capital contributions.

Commitments and Contractual Obligations

As of December 31, 2011, 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 "Business 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. We review our estimates, including those related to oil and natural gas revenues, oil and natural gas properties, oil 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, shall not exceed an amount (the ceiling) equal to the sum of: (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; (ii) the cost of properties not being amortized; and (iii) the lower of cost or estimated fair value of unproven properties included in the costs being amortized less related effects of income taxes, if any. 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 and natural gas reserves with oil 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 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 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 Financial Accounting Standards Board 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 is intended to provide investors with a more meaningful and comprehensive understanding of oil and natural gas reserves, which should help investors evaluate the relative value of oil and natural gas companies. 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 new disclosure requirements require 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.

Unproved Properties and Impairments

Depreciation, depletion, and amortization is provided using the unit-of-production method based upon estimates of proved oil and natural gas reserves with oil 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.

Asset Retirement Obligations

We comply with ASC 410-20 to 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, offshore production platforms, and natural gas processing plants. 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, and well life. The inputs are calculated based on historical data as well as current estimates. When the liability is initially recorded, the entity increases 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, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement which the entity treats as an adjustment to the full cost pool. This standard requires us to record a liability for the fair value of the dismantlement and abandonment costs, excluding salvage values.

Revenue Recognition

Oil 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 and natural gas sales such that revenues are recognized based on our share of actual proceeds from the oil 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 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 unrealized gains or losses on derivative contracts.

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 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 and natural gas production. Realized pricing is primarily driven by the spot market prices applicable to our natural gas production and the prevailing price for oil. Pricing for oil 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 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, 2011, we had a commodity derivative contract covering 1,000 Bopd for the 2012 fiscal year. The contract is a put spread where we are long a $90 oil put and short a $70 oil put. Our put spread protects us from oil prices falling below $90 until such time as prices fall below $70, in which case we receive the market price plus the $20 spread between $90 and $70. We used a portion of the proceeds from our IPO to pay a deferred premium of $1.9 million. As a result, any cash settlements will involve payment from our counterparty to us, with us having no contractual payment obligations to the counterparty.

As of December 31, 2011, the fair value of our commodity derivative contract was an asset of approximately $1.5 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, 2011 price would result in a decrease in the fair value of our commodity derivative contract of approximately $0.6 million; conversely, a 10% decrease in the oil index price would result in an increase of approximately $0.9 million.

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.

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 2011, 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

This annual report does not include management's assessment regarding internal control over financial reporting or an attestation report of our independent registered public accounting firm due to a transition period established by rules of the SEC for newly public 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, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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

None.

PART III

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

Information regarding our directors, executive officers and certain corporate governance items will be included in an amendment to this Form 10-K or in the proxy statement for the 2012 annual meeting of stockholders, in either case, to be filed within 120 days after December 31, 2011, 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 2012 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 2012 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 2012 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 2012 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 of "analogous reservoir," "development costs," "development project," "development well," "economically producible," "estimated ultimate recovery," "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.

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.

estimated ultimate recovery ("EUR"): Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

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

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

field: An area consisting of a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. The field name refers to 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.

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 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 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).
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).
10.3*	Sanchez Energy Corporation 2011 Long Term Incentive Plan (filed as Exhibit 10.3 to Amendment No. 5 to the Company's registration statement on Form S-1 (File. No. 333-176613) on December 7, 2011, and incorporated herein by reference).

Exhibit No.	Description of Exhibit
10.4	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).
10.5	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).
10.6	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).
10.7	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).
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, 2011 Reserves.

(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 30, 2012.

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 capacity and on the dates indicated:

Signature	Title	Date
/s/ ANTONIO R. SANCHEZ, III Antonio R. Sanchez, III	Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)	March 30, 2012
/s/ MICHAEL G. LONG Michael G. Long	Senior Vice President, Chief Financial Officer and Secretary (Principal Financial Officer)	March 30, 2012
/s/ KIRSTEN A. HINK Kirsten A. Hink	Vice President and Principal Accounting Officer (Principal Accounting Officer)	March 30, 2012
/s/ GILBERT A. GARCIA Gilbert A. Garcia	Director	March 30, 2012
/s/ GREG COLVIN Greg Colvin	Director	March 30, 2012

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, 2011 and 2010 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, 2011. 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 1, 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, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

/s/ BDO USA, LLP

Houston, Texas
March 30, 2012

Sanchez Energy Corporation

Consolidated Balance Sheets

(in thousands, except share and per share amounts)

	As of December 31, 2011	As of December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 63,041	$ —
Oil and natural gas receivables	1,193	2,725
Derivative assets	1,461	—
Other current assets	327	—
Total current assets	66,022	2,725
Oil and natural gas properties, at cost, using the full cost method:		
Unproved oil and natural gas properties	126,201	20,823
Proved oil and natural gas properties	31,836	5,674
Total oil and natural gas properties	158,037	26,497
Less: Accumulated depreciation, depletion, amortization and impairment	(6,703)	(2,457)
Total oil and natural gas properties, net	151,334	24,040
Total assets	$217,356	$26,765
LIABILITIES AND PARENT NET INVESTMENT / STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable—related entities	$ 1,606	$ —
Accrued liabilities	526	4,543
Total current liabilities	2,132	4,543
Asset retirement obligation	83	60
Total liabilities	2,215	4,603
Commitments and contingencies (Note 10)		
Parent net investment / stockholders' equity		
Parent net investment	—	22,162
Preferred stock ($0.01 par, 15,000,000 shares authorized; none issued and outstanding)	—	—
Common stock ($0.01 par, 150,000,000 shares authorized; 33,000,000 issued and outstanding)	330	—
Additional paid-in capital	215,115	—
Accumulated deficit	(304)	—
Total parent net investment / stockholders' equity	215,141	22,162
Total liabilities and parent net investment / stockholders' equity	$217,356	$26,765

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)

	Years Ended December 31,		
	2011	2010	2009
REVENUES:			
Oil sales	$13,905	$ 4,404	$ 241
Natural gas sales	611	149	—
Total revenues	14,516	4,553	241
OPERATING COSTS AND EXPENSES:			
Oil and natural gas production expenses	1,628	391	9
Production and ad valorem taxes	830	214	11
Depreciation, depletion and amortization	4,246	1,428	415
Accretion expense	6	2	—
Impairment of oil and natural gas properties	—	—	614
Gain on sale of oil and natural gas properties	—	—	(2,686)
General and administrative	5,368	5,276	1,833
Total operating costs and expenses	12,078	7,311	196
Operating income (loss)	2,438	(2,758)	45
Other income (expense):			
Interest and other income	10	—	—
Unrealized loss on derivatives	(480)	—	—
Net income (loss)	$ 1,968	$ (2,758)	$ 45
Net income (loss) per share—basic and diluted	$ 0.09	$ (0.12)	$ —
Weighted average shares outstanding used in computing net income (loss) per share—basic and diluted	22,479	22,091	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)

	Shares	Amount	Additional Paid-in Capital	Accumulated Deficit	Parent Net Investment	Total Stockholders' Equity
BALANCE, December 31, 2008	—	$ —	$ —	$ —	$ 14,197	$ 14,197
Distribution to parent	—	—	—	—	(1,024)	(1,024)
Net income	—	—	—	—	45	45
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 Marquis in exchange for common stock	909	9	19,991	—	—	20,000
Shares issued in inital 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

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

Sanchez Energy Corporation

Consolidated Statements of Cash Flows

(in thousands)

	Years Ended December 31,		
	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 1,968	$ (2,758)	$ 45
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Gain on sale of oil and natural gas properties	—	—	(2,686)
Depreciation, depletion and amortization	4,246	1,428	415
Impairment of oil and natural gas properties	—	—	614
Accretion expense	6	2	—
Unrealized loss on derivatives	480	—	—
Changes in operating assets and liabilities:			
Accounts receivable	(962)	(2,619)	(106)
Other current assets	(327)	—	—
Accounts payable—related entities	1,606	—	—
Accrued liabilities	461	170	8
Net cash provided by (used in) operating activities	7,478	(3,777)	(1,710)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Payments for oil and natural gas properties	(20,578)	(13,848)	(3,098)
Proceeds from sale of oil and natural gas properties	1,587	5,923	5,832
Acquisition of Marquis properties	(89,014)	—	—
Premium paid on derivative contracts	(1,932)	—	—
Net cash provided by (used in) investing activities	(109,937)	(7,925)	2,734
CASH FLOWS FROM FINANCING ACTIVITIES:			
Issuance of common stock	220,000	—	—
Payments for offering costs	(16,686)	—	—
Net investment by (distribution to) parent	(37,814)	11,702	(1,024)
Net cash provided by (used in) financing activities	165,500	11,702	(1,024)
Increase in cash and cash equivalents	63,041	—	—
Cash and cash equivalents, beginning of period	—	—	—
Cash and cash equivalents, end of period	$ 63,041	$ —	$ —
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Asset retirement obligation	$ 17	$ 47	$ 10
Change in accrued capital expenditures	3,518	4,326	(26)
Accounts receivable distributed to parent	2,494	—	—
Accounts payable assumed by parent	(8,005)	—	—
Purchase of oil and natural gas properties from Marquis in in exchange for common stock	20,000	—	—

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 Basis of Presentation

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 acquisition, exploration, and development of unconventional oil and natural gas resources primarily in the Eagle Ford Shale in South Texas. As of December 31, 2011, the Company had accumulated acreage in 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.

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 estimated expenses and underwriting discounts and commissions).

On December 19, 2011, the Company entered into a contribution, conveyance and assumption agreement whereby Sanchez Energy Partners I, LP ("SEP I) 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 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 is a transaction among entities under common control and accordingly, the Company has recognized 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 presented in its December 31, 2011 financial statements. In addition, the $50.0 million payment was reflected as a distribution to SEP I in the accompanying financial statements. As a result of this transaction, SEP I became the Company's largest stockholder, holding approximately 66.9% of the Company's outstanding common stock at December 31, 2011.

The Company also entered into a contribution agreement whereby it acquired 100% of the limited liability company interests in SN Marquis LLC, which owned 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 million, and approximately $89.0 million in cash, subject to adjustment, from the proceeds of the IPO. The acquisition was accounted for as a purchase of assets and recorded at cost at the acquisition date. As only undeveloped leaseholds were acquired, no associated operating results are reflected in the accompanying consolidated financial statements for the year ended December 31, 2011.

On December 19, 2011, the Company entered into a services agreement and other related agreements with Sanchez Oil & Gas Corporation ("SOG"), an entity under common control, 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 1. Organization and Basis of Presentation (Continued)

Basis of Presentation

The 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 is a transaction under common control and accordingly, the Company has recognized the assets and liabilities acquired at their historical carrying values and presented the historical accounts of the SEP I Assets on a retrospective basis for all periods presented in the accompanying consolidated financial statements.

For periods prior to December 19, 2011, the accompanying consolidated financial statements have been 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 their results of operations, financial position, and cash flows would have been had the SEP I Assets operated as an independent company.

SEP Management I, LLC is the General Partner of SEP I and is a wholly owned subsidiary of SOG. 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. Pursuant to a management services agreement, SOG provides all employee, management, and administrative support to SEP I and, accordingly, through December 18, 2011, a proportionate share of SOG's general and administrative costs have been allocated to the SEP I Assets. For purposes of these financial statements, 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 are reasonable; however, they may not be indicative of the actual expense that would have been incurred had the SEP I Assets operated as an independent company for the periods prior to December 19, 2011. SOG will continue to provide these services to the Company under the services agreement described above.

Note 2. Business and Summary of Significant Accounting Policies

Description of Business

The Company's properties are primarily located in the oil window of the Eagle Ford Shale in Texas and are operated by SOG. 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 are not operated by SOG. The principal markets for the Company's products are the sale of such products at the wellhead or by transporting production to purchasers' purchase points.

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.

Note 2. Business and Summary of Significant Accounting Policies (Continued)

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. Significant assumptions are required in the quantification and valuation of proved oil and natural gas reserves, which as described herein may affect the amount at which oil and natural gas properties are recorded and related depreciation, depletion, amortization and impairment are calculated. Other significant estimates include but are not limited to the valuation of commodity derivatives, asset retirement obligations, and through December 18, 2011, the allocation of general and administrative expenses. Actual results could differ materially from those estimates.

Reclassification

Certain reclassifications have been made to the 2010 and 2009 consolidated financial statements to conform to the 2011 presentation. These reclassifications were not material to the accompanying consolidated financial statements.

Cash Equivalents

The Company considers all highly liquid investments with original contract maturities of three months or less to be cash equivalents.

Oil and Natural Gas Receivables

All of the Company's receivables arise from sales of oil or natural gas. The Company does not have any off-balance-sheet credit exposure related to its customers. Receivables from the sale of oil and natural gas are generally unsecured. Allowances for doubtful accounts are determined based on management's assessment of the creditworthiness of the customer. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are written off against the allowance for doubtful accounts only after all the collection attempts have been exhausted. At December 31, 2011 and 2010, 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. These costs, as well as the estimated costs to retire the assets are included in the amortization base and amortized to expense using the units-of-production method. Amortization 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 value 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

Note 2. Business and Summary of Significant Accounting Policies (Continued)

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 the Securities and Exchange Commission ("SEC") rules, the natural gas and oil 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. Price is 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, 2011 or 2010. Impairment expense of $0.6 million was recorded during the year ended December 31, 2009.

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

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

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 and natural gas reserves, in which case the gain or loss is recognized in the statement of operations. In December 2009, a portion of certain unevaluated oil and natural gas acreage was sold for cash of approximately $5.0 million. Because a reduction in the full cost pool by the net sales proceeds would have significantly altered the relationship between capitalized costs and proved reserves, the sale was considered significant and a $2.7 million gain was recorded in the statement of operations.

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

Note 2. Business and Summary of Significant Accounting Policies (Continued)

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, 24%, 26% and 24% of the unproved property balance at December 31, 2011 is expected to be added to the amortization base during the years 2012, 2013 and 2014, respectively. The remaining balances in unproved properties relate to project areas that will not be thoroughly evaluated until after 2014, and represent leasehold interests that have expiration dates beginning in 2017.

The table below sets forth the cost of unproved properties excluded from the amortization base as of December 31, 2011 and notes the year in which the associated costs were incurred:

	Year of Acquisition				
	2008	2009	2010	2011	Total
	(in thousands)				
Leasehold acquisition cost	$4,593	$ 588	$6,088	$111,110	$122,379
Exploration cost	1,196	977	171	1,478	3,822
Total	$5,789	$1,565	$6,259	$112,588	$126,201

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, 2011, 2010 and 2009 are based on reports prepared by Ryder Scott Company, LP ("Ryder Scott").

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

Note 2. Business and Summary of Significant Accounting Policies (Continued)

(the "Final Rule"). The Final Rule was issued on December 31, 2008 and was intended 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 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.

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, 2011 and 2010.

Note 2. Business and Summary of Significant Accounting Policies (Continued)

Asset Retirement Obligations

The Company records the fair value of a liability for the legal obligation to retire an asset in the period in which it is incurred. Corresponding costs are capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, the difference is recognized in proved oil and natural gas properties.

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, 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.

Revenue Recognition

Oil 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 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, 2011 and 2010, there were no oil and natural gas imbalances.

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 years ended December 31, 2010 and 2009 was approximately $4.3 million, $5.1 million and $1.7 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 is 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. Business and Summary of Significant Accounting Policies (Continued)

Fair Value of Financial Instruments

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

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 statement of operations as unrealized gains or losses on derivative contracts.

In April, 2011, based on increased oil production and the commitment to continue an aggressive drilling program in the Eagle Ford Shale, certain crude oil put spread derivatives were entered into covering oil production for calendar year 2012. The derivatives include the purchase of puts with a strike price of $90 per barrel on 1,000 barrels per day and the corresponding sale of puts with a strike price of $70 per barrel for 1,000 barrels per day. The net cost of the put spread was approximately $1.9 million. The Company used a portion of the proceeds from its IPO to pay the net cost of the put spread. As a result, any cash settlements will involve payment from the counterparty to the Company, with the Company having no contractual payment obligations to the counterparty.

An unrealized loss on the above derivatives in the amount of $0.5 million was recorded during the year ended December 31, 2011. No derivative transactions were in place during the years 2010 or 2009.

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, was allocated to the limited and general partners of SEP I. With the transfer of the SEP I Assets to the Company, the SEP I Assets' operations are now 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. Business 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, 2011.

Earnings per Share

Basic earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding during the period, giving retroactive effect to the 22,090,909 shares issued to SEP I on December 19, 2011, as discussed in Note 1. Diluted earnings per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net income by the sum of the weighted average number of shares of common stock outstanding plus all potentially dilutive securities. The Company does not have any potentially dilutive securities outstanding as of December 31, 2011.

Note 3. 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 estimated expenses and underwriting discounts and commissions).

Earnings (Loss) 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 the transactions. Basic and diluted net earnings (loss) per share are the same, as there are no potentially dilutive shares for any period presented.

Note 4. Income Taxes

The SEP I Assets 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 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 are now subject to federal and state income taxes.

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

Deferred recognized at date of acquisition	$(8,727)
Deferred as a result of current operations	(106)
Provision for income taxes	(8,833)
Valuation allowance	8,833
Net provision for income taxes	$ —

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

Income tax expense at the federal statutory rate	$ 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)
Income tax provision	(8,833)
Valuation allowance	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 used for income tax reporting. Significant components of the deferred tax assets are as follows (in thousands):

Deferred tax assets:	
Current:	
Derivative obligations	$ 165
Total current deferred tax assets	165
Noncurrent:	
Net operating loss carryforwards	778
Depreciable, depletable property, plant and equipment	7,890
Total noncurrent deferred tax assets	8,668
Total deferred tax assets	8,833
Valuation allowance	(8,833)
Net deferred tax assets	$ —

Note 4. Income Taxes (Continued)

At December 31, 2011, the Company had net operating loss carryforwards of $2.2 million which 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, management is not able 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, 2011. The Company will continue to assess the valuation allowance against deferred tax assets considering all available information obtained in future reporting periods.

Note 5. 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, remediation costs, and well life. The inputs are calculated based on historical data as well as current estimates. When the liability is initially recorded, the entity increases 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, any gain or loss is treated as an adjustment to the full cost pool.

The following roll forward is provided as a reconciliation of the beginning and ending balance associated with the asset retirement obligation.

	2011	2010
Abandonment liability as of January 1,	$59,906	$10,332
Liabilties incurred during period	17,202	47,158
Accretion expense	5,756	2,416
Revision of estimate	—	—
Abandonment liability as of December 31,	$82,864	$59,906

Note 6. Related Party Transactions

SOG, headquartered in Houston, Texas, is a private full service oil and natural gas company engaged in the exploration and development of oil and natural gas primarily in the South Texas and onshore Gulf Coast areas on behalf of its affiliates. The Company refers to SOG, SEP I, and their affiliates (but excluding the Company) collectively as the "Sanchez Group." Members of the Sanchez Group control the majority of the voting power of our outstanding common stock.

Note 6. Related Party Transactions (Continued)

Administrative Services and Other Agreements

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 provision of 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 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 in the accompanying financial statements. These costs were allocated based on the approximate ratio of capital expenditures between the entities to which SOG provided 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, expenses allocated to the Company for general and administrative expenses and the reimbursements of actual third-party expenses incurred by SOG (including charges pursuant to

Note 6. Related Party Transactions (Continued)

the services agreement), or amounts paid directly by other members of the Sanchez Group on SOG's behalf, are as follows:

	Year Ended December 31,		
	2011	2010	2009
	(in thousands)		
Administrative fees	$4,314	$5,142	$1,725
Third-party expenses	1,054	134	108
Total general and administrative expenses	$5,368	$5,276	$1,833

As of December 31, 2011, the Company had a payable to SOG of $1.2 million and a payable to SEP I of $0.4 million which is reflected as "Accounts payable—related entities" in the accompanying Consolidated Balance Sheets.

Note 7. 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

Note 7. Fair Value of Financial Instruments (Continued)

liabilities and their placement within the fair value hierarchy levels. As of December 31, 2010, there were no financial assets or liabilities measured at fair value on a recurring basis.

Derivatives

At December 31, 2011, the Company's oil put spread contracts, with a net fair value of $1.5 million, were classified as Level 3.

The following table sets forth a reconciliation of changes in the fair value of oil put spread derivative asset classified as Level 3 in the fair value hierarchy during the year ended December 31, 2011 (in thousands):

Beginning balance	$ —
Additions	1,941
Unrealized losses	(480)
Ending balance	$1,461
Change in unrealized losses included in earnings related to derivatives still held at period end	$ (480)

Non-Financial Assets and Liabilities

The fair value of non-financial assets and liabilities, such as asset retirement obligations and impairments of unevaluated oil and natural gas properties, are recognized on a non-recurring basis. See Notes 2 and 5 for further information.

Note 8. Sales to Major Customers

The Company's oil and natural gas production was sold to certain customers representing 10% or more of its total revenues for the years ended December 31, 2011, 2010 and 2009 as listed below:

	2011	2010	2009
Customer A	—	—	100%
Customer B	68%	81%	—
Customer C	6%	19%	—
Customer D	22%	—	—

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.

Note 9. Long Term Incentive Plan

On November 25, 2011, the Company's board of directors approved the Sanchez Energy Corporation 2011 Long Term Incentive Plan (the "LTIP" or "2011 Plan").

The Company's directors and consultants as well as employees of the Sanchez Group are eligible to participate in the 2011 Plan. 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 2011 Plan is limited to 12% of the Company's issued and outstanding shares of common stock. This maximum amount automatically increases to 12% 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 of directors determines to increase the maximum number of shares of common stock by a lesser amount. Shares withheld to satisfy tax withholding obligations will not be 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 will again be available for new awards under the LTIP. Shares to be 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 of directors. The Company's board of directors 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 of directors 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 of directors 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.

As of December 31, 2011, no awards were granted under the LTIP and 3,960,000 shares remained available for future issuance to participants. In January 2012, restricted stock awards were granted to a director of the Company and certain employees of the Sanchez Group. See Note 11, "Subsequent Events".

Restricted stock is common stock that vests over a period of time and that during such time is subject to forfeiture. Such restricted stock is issued on the grant date, but is restricted as to transferability. Restricted stock grants generally vest over periods ranging from two to three years as determined by the Company's board of directors at the time of grant. Compensation costs for all awards of restricted stock under the LTIP will be based on the closing market price of the Company's common stock on the date of grant. Share-based compensation expense will be based on the awards ultimately expected to vest, with a reduction for estimated forfeitures.

Note 10. 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 11. Subsequent Events

In January 2012, the Company issued 1.6 million shares of restricted common stock pursuant to the Company's LTIP to a director of the Company and certain employees of the Sanchez Group. Approximately 1.1 million shares of restricted common stock vest equally over a two-year period and approximately 0.5 million shares of restricted common stock vest equally over a three-year period.

Subsequent to December 31, 2011, the Company modified its existing put spread transaction by purchasing the original $70 per barrel put that it had sold in 2011 over the July through December time period covering 1,000 barrels per day of production, leaving the Company with only a $90 per barrel put for that time period. The Company also entered into a new put spread transaction for an additional 1,250 barrels of production per day, buying a $100 per barrel put and selling an $80 put for the July through December 2012 time period.

The Company also entered into the purchase of put spread contracts with a strike price of $95 per barrel on 1,000 barrels per day covering oil production for calendar year 2013 and the corresponding sale of puts with a strike price of $75 per barrel for the same 1,000 barrels per day.

The net cost of modified and new derivative contracts discussed above was approximately $3.1 million.

Note 12. Supplemental Financial Quarterly Results (Unaudited)

The following table presents the Company's unaudited quarterly financial information for 2011 and 2010:

	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
	(in thousands, except per share amounts)			
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 (loss)	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 earnings (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
2010:				
Oil and natural gas revenue	$ 3,088	$ 1,132	$ 258	$ 75
Operating costs and expenses	(2,727)	(1,682)	(1,535)	(1,367)
Operating income (loss)	361	(550)	(1,277)	(1,292)
Other income (expense), net	—	—	—	—
Net income (loss)	$ 361	$ (550)	$(1,277)	$(1,292)
Basic and diluted earnings (loss) per share(1)	$ 0.02	$ (0.02)	$ (0.06)	$ (0.06)
Weighted average shares outstanding—basic and diluted	22,091	22,091	22,091	22,091

(1) 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 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:

	As of December 31,		
	2011	2010	2009
		(in thousands)	
Oil and Natural Gas Properties:			
Unproved	$126,201	$20,823	$12,973
Proved	31,836	5,674	1,226
Total Oil and Natural Gas Properties	158,037	26,497	14,199
Less Accumulated depreciation, depletion, amortization and impairment	(6,703)	(2,457)	(1,030)
Net oil and natural gas properties capitalized	$151,334	$24,040	$13,169

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

	Years Ended December 31,		
	2011	2010	2009
		(in thousands)	
Unproved property acquisition costs	$111,224	$ 8,964	$ 346
Exploration costs	1,670	6,377	2,736
Development costs	20,234	2,880	—
Total Costs Incurred	$133,128	$18,221	$3,082
Seismic costs included in exploration costs	$ —	$ 249	$1,753

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

	Years Ended December 31,		
	2011	2010	2009
	(in thousands)		
Oil and natural gas revenue	$14,516	$ 4,553	$ 241
Less operating expenses:			
Oil and natural gas production expenses	(1,628)	(391)	(9)
Production and ad valorem taxes	(830)	(214)	(11)
Depreciation, depletion, and amortization	(4,246)	(1,428)	(415)
Accretion expense	(6)	(2)	—
Impairment of oil and natural gas properties	—	—	(614)
Gain on sale of oil and natural gas properties	—	—	2,686
Results of operations from oil and gas producing activities	$ 7,806	$ 2,518	$1,878

Reserves—Proved reserves are those quantities of oil 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 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, 2011, 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. The Company had no proved reserves at year end 2008.

Proved reserves for all periods presented were estimated in accordance with the guidelines established by the SEC and the 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, 2011, 2010 and 2009 was based on an unweighted twelve month West Texas Intermediate posted price of $96.19, $79.43 and $61.18, respectively. For natural gas the average price was based on an unweighted twelve month Henry Hub spot natural gas price average of $4.12, $4.38 and $3.86 as of December 31, 2011, 2010 and 2009, respectively.

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, 2009 2010 and 2011. No proved reserves were associated with the SEP I Assets at December 31, 2008.

	Oil (MBo)	Gas (MMCF)	MBOE(1)
Balance as of December 31, 2008	—	—	—
Extensions and discoveries	10	6	11
Production	(4)	—	(4)
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)	456	(14)
Extensions and discoveries(2)	3,215	3,476	3,795
Production	(146)	(167)	(174)
Balance as of December 31, 2011	5,610	6,418	6,680
Proved developed reserves:			
As of December 31, 2009	6	6	7
As of December 31, 2010	362	1,541	619
As of December 31, 2011	689	1,674	968
Proved undeveloped reserves:			
As of December 31, 2009	—	—	—
As of December 31, 2010	2,269	1,112	2,454
As of December 31, 2011	4,921	4,744	5,712

(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, an additional three successful wells were drilled on the same acreage which resulted in the recording of additional undeveloped reserves at December 31, 2011.

Standardized Measure—The Standardized Measure of Discounted Future Net Cash Flows relating to the Company's ownership interest in proved oil and natural gas reserves for each of the three years ended December 31, 2011 is shown below:

	As of December 31,		
Standardized Measure	**2011**	**2010**	**2009**
	(in thousands)		
Future cash inflows	$ 545,566	$214,496	$ 350
Future production costs	(124,895)	(46,468)	(144)
Future development costs	(152,000)	(70,049)	—
Future income taxes(1)	(33,955)	—	—
Discount to present value at 10% annual rate	(101,558)	(47,268)	(9)
Standardized measure of discounted future net cash flows	$ 133,158	$ 50,711	$ 197

(1) Amounts as of December 31, 2010 and 2009 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 and natural gas reserves are summarized below:

	For the Years Ended December 31,		
Summary of Changes	**2011**	**2010**	**2009**
	(in thousands)		
Balance, beginning of period	$ 50,711	$ 197	$ —
Changes in prices and costs	9,512	44	—
Revisions of previous quantity estimates	(401)	(30)	—
Extensions and discoveries	135,574	88,538	419
Sales of oil and gas—net of production costs	(12,059)	(3,948)	(222)
Net change in income taxes	(19,264)	—	—
Changes in development costs	(46,492)	(36,255)	—
Accretion of discount	5,071	20	—
Other—net	10,506	2,145	—
Net change	82,447	50,514	197
Balance, end of period	$133,158	$ 50,711	$ 197

CORPORATE INFORMATION

BOARD OF DIRECTORS

Antonio R. Sanchez, III #
Chairman of the Board and
Chief Executive Officer

Gilbert Garcia #
Managing Partner of
Garcia Hamilton & Associates

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

Member of the Audit committee

SENIOR MANAGEMENT

Antonio R. Sanchez, III
Chairman of the Board and
Chief Executive Officer

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

Patrick Talamas
Senior Vice-President of Geoscience

Kirsten A. Hink
Chief Accounting Officer

CORPORATE ADDRESS

Sanchez Energy Corporation
1111 Bagby, Suite 1600
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, TX 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 77004

LEGAL COUNSEL

Akin Gump Straus 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 23, 2012.

FORM 10-K

Copies of the Company's Annual Report ond 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