EPL OIL & GAS, INC.
Form 10-K
February 28, 2014

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2013

or

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

For the transition period from to

Commission file number: 001-16179

EPL Oil & Gas, Inc.

(Exact name of registrant as specified in its charter)

Delaware	72-1409562
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

919 Milam Street, Suite 1600, Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

(713) 228-0711

Registrant's telephone number, including area code

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of exchange on which registered
Common Stock, Par Value $0.001 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 x 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 ¨ Nox

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. Yesx 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 x 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. x

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 x

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yesx No ¨

The aggregate market value of the common stock held by non-affiliates of the registrant at June 30, 2013 (the registrant's most recently completed second fiscal quarter) based on the closing stock price as quoted on the New York Stock Exchange on that date was $1,066,066,044. As of February 21, 2014, there were 39,206,958 shares of the registrant's common stock, par value $0.001 per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Proxy Statement for the Annual Meeting of Stockholders of EPL Oil & Gas, Inc. expected to be held on May 1, 2014 are incorporated by reference into Part III of this Annual Report on Form 10-K.

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Statements we make in this Annual Report on Form 10-K ("Annual Report") which express a belief, expectation or intention, as well as those that are not historical fact, may constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Our forward-looking statements are subject to various risks, uncertainties and assumptions, including those to which we refer under the headings "Cautionary Statement Concerning Forward-Looking Statements" and "Risk Factors" in Items 1 and 1A of Part 1 of this Annual Report.

PART I

Item 1.Business

Overview

EPL Oil & Gas, Inc. (referred to herein as "we," "our," "us" or the "Company") was incorporated as a Delaware corporation in January 1998 and operates as an independent oil and natural gas exploration and production company based in Houston, Texas and New Orleans, Louisiana. Effective September 1, 2012, we changed our legal corporate name from "Energy Partners, Ltd." to "EPL Oil & Gas, Inc." through a short-form merger pursuant to Section 253 of the General Corporation Law of the State of Delaware. Our current operations are concentrated in the U.S. Gulf of Mexico shelf focusing on state and federal waters offshore Louisiana, which we consider our core area. We have focused on acquiring and developing assets in this region, because the region is characterized by established exploitation, development and exploration opportunities in both productive horizons and deeper geologic formations. Our management professionals and technical staff have considerable geological, geophysical and operational experience that is specific to the Gulf of Mexico and Gulf Coast region, and we have acquired and developed geophysical and geological data relating to these areas. We intend to pursue capital-efficient development and exploration activities in our core area, as well as identify acquisition opportunities that leverage our technical and operational strengths. As of December 31, 2013, we had estimated proved reserves of 80.4 Mmboe, of which 64% were oil and 71% were proved developed. Of these proved developed reserves, 69% were oil reserves.

We produce both oil and natural gas. Throughout this Annual Report, when we refer to "total production," "total reserves," "percentage of production," "percentage of reserves," or any similar term, we have converted our natural gas reserves or production into barrel equivalents. For this purpose, six thousand cubic feet of natural gas is equal to one barrel of oil, which is based on the relative energy content of natural gas and oil. Natural gas liquids are aggregated with oil in this Annual Report.

For definitions of oil and natural gas terms used frequently in this Annual Report, please refer to the "Glossary of Oil and Natural Gas Terms" following the index of Exhibits in Item 15 of Part IV of this Annual Report.

The following summarizes our acquisitions (purchase prices are before economic effective date adjustments):

Acquisitions

- On January 15, 2014, we acquired 100% working interest of certain shallow-water central Gulf of Mexico shelf oil and natural gas assets in the Eugene Island 258/259 field for $70.4 million (the "Nexen Acquisition");
- On September 26, 2013, we acquired an asset package consisting of certain Gulf of Mexico shelf oil and natural gas interests in the West Delta 29 field (the "WD29 Interests") for $21.8 million;
- On October 31, 2012, we acquired 100% of the membership interests of Hilcorp Energy GOM, LLC ("Hilcorp Acquisition"), which owned certain shallow water Gulf of Mexico shelf oil and natural gas interests (the "Hilcorp Properties") for $550 million. The Hilcorp Properties included three core producing complexes in the Ship Shoal 208, South Pass 78 and South Marsh Island 239 areas;
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On May 15, 2012, we acquired an asset package consisting of certain shallow-water Gulf of Mexico shelf oil and natural gas interests in our South Timbalier 41 field located in the Gulf of Mexico for $32.4 million (the "ST41 Interests");

- On November 17, 2011, we acquired interests in the Main Pass 296/311 complex along with other unit interests in the Main Pass complex and an interest in a Main Pass 295 primary term lease for $38.6 million (the "Main Pass Interests"); and
- On February 14, 2011, we acquired from Anglo-Suisse Offshore Partners, LLC ("ASOP") an asset package consisting of certain shallow-water Gulf of Mexico shelf oil and natural gas interests surrounding the Mississippi River delta and a related gathering system (the "ASOP Properties") for $200.7 million. The ASOP Properties included two core producing complexes in the West Delta and Main Pass areas and an interest in the South Pass 49 field.

Dispositions

- On April 2, 2013, we sold certain shallow water Gulf of Mexico shelf oil and natural gas interests located within the non-operated Bay Marchand field for total consideration of $62.8 million.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations" for more information regarding these transactions.

Competitive Strengths

High Quality Asset Base with Significant Exploitation and Exploration Potential. We believe our asset base is characterized by lower-risk properties that have more predictable well control and production profiles. Our net proved reserves as of December 31, 2013 were 71% proved developed, which provides significant production visibility. Moreover, we have an inventory of lower risk exploitation projects with 209 behind pipe opportunities and 35 identified proved undeveloped reserves locations. Our portfolio of fields offer significant development and exploration potential, with multiple producing zones and unexplored deeper horizons.

Oil-Weighted Reserves and Production. We believe we are more oil-focused in both our reserves and production as compared to many of our peers. Our net proved reserves at December 31, 2013 were approximately 64% oil, and our net average daily production for the year ended December 31, 2013 was 76% oil. Given the current commodity price environment and resulting disparity between oil and natural gas prices on a barrel of oil equivalent basis, we believe our high percentage of oil reserves compared to our overall reserve base provides us an economic advantage. Additionally, the production decline curve of oil is typically lower than a natural gas decline curve, resulting in longer term production from current reserves.

Operational Control. We operate properties that contain approximately 89% of our proved reserves. As the operator of a property, we are afforded greater control of the optimization of production, the timing and amount of capital expenditures, and the operating parameters and costs of our projects. As such, we are able to align capital expenditures with cash flow because we are generally able to adjust drilling and development plans in response to changes in commodity prices.

Geographically Focused Properties in the Gulf of Mexico. We are focused on operating properties located in the Gulf of Mexico shelf, which gives us the opportunity to minimize logistical and administrative costs and maximize the productivity of our field personnel. Our concentration of long-lived, oil rich legacy fields provides attractive future consolidation opportunities as evidenced by the Hilcorp and Nexen acquisitions. Our experience in the Gulf of Mexico, and particularly offshore Louisiana, has led us to focus our efforts in that particular region, where we are familiar with the fields, drilling and production trends and where we have amassed an extensive library of geologic information.

In 2012 we acquired additional 2-D and 3-D seismic data sets in our current offshore operating areas and onshore Louisiana where the geology is characterized by similar productive horizons and structural features. In addition to the extensive seismic library we have of our legacy properties, we have licensed high quality multi-client 3-D data sets for recently acquired fields. We now have approximately 21,119 square miles of 3-D seismic data in the Gulf of Mexico and onshore Louisiana. This seismic data assists us in identifying attractive development and exploration drilling opportunities that adhere to our capital-efficient development strategies. We continue to high-grade these data sets by employing state-of-the-art reprocessing techniques for the data covering our core fields and on a regional basis around those fields. These technological upgrades are creating better images of prospective horizons and aiding in the evaluation of drilling opportunities.

Additionally, in September and October 2013, we negotiated agreements totaling approximately $45 million with seismic companies to acquire 3-D seismic licenses over our core areas. These agreements include a commitment to acquire area-wide data licenses for seismic acquisitions that will be performed by the seismic company during 2014, 2015 and 2016 covering a minimum of 200 blocks, or approximately one million acres, within the shallow water Gulf of Mexico covering our core asset base.

Conservative Fiscal Policy. We budget our capital spending on exploration and development with the goal of remaining within cash flow from operations. We have hedged approximately 67% of our forecasted oil production for 2014 and have begun hedging forecasted production for 2015.

Experienced Management and Significant Technical Expertise. We have an experienced and technically-adept management team, averaging more than 25 years of industry experience among our top nine executives. We have also built a strong technical staff of geologists and geophysicists, field operations managers and engineers to handle all aspects of our exploitation, exploration, production and decommissioning activities. During the current year, we brought on eight additional geoscientists, engineers and technicians.

Business Strategy

Pursue Capital Efficient Development in Core Areas. Our current producing asset base in the Gulf of Mexico shelf includes a large inventory of lower-risk exploitation opportunities, as well as exploration prospects with multiple objectives and follow-up opportunities. In 2013, we completed 21 workovers and 17 drill wells, with a 79% success rate, spending approximately $335.9 million on development and exploration activities and a total of $12.3 million on seismic purchases. We also spent approximately $2 million on undeveloped leases in 2013. Our fiscal year 2014 capital budget is $360 million, which is allocated to development activities and exploration projects within core field areas. Additionally, we plan to spend approximately $50 million in 2014 on plugging, abandonment and other decommissioning activities. We will continue to focus on lower-risk development projects, as well as a small number of high quality, high potential exploration prospects. We believe the properties we acquired in recent years enhance our exploitation strategy to increase production from legacy fields and provide us with substantial incremental exploration opportunities within those fields.

Build upon Regional Geologic Expertise. We are dedicating significant resources to add to our knowledge of the geology underlying our core areas. As previously described, in September and October 2013, we negotiated agreements totaling approximately $45 million with seismic companies to acquire 3-D seismic licenses over our core areas through 2017, of which we expect to spend approximately $13 million in 2014. We also have recently acquired additional 2-D and 3-D seismic data sets in our current offshore operating areas and onshore Louisiana, where the geology is characterized by similar productive horizons and structural features. Our geological and geophysical teams are analyzing well data, paleontological data and seismic data to identify exploration targets at intermediate and deep depths as well as associated acquisition opportunities.

Target Acquisition Opportunities to Grow Reserves and Leverage Operational Strengths. We continue to review and monitor opportunities to acquire producing properties, leasehold acreage and drilling prospects in and around our core areas of operation so that we can act quickly as acquisition opportunities become available. Our acquisition strategy is focused on operated Gulf of Mexico shelf and Gulf Coast assets that are characterized by production-weighted reserves, seismic coverage and operated positions that would allow us to maintain a conservative capital structure. We intend to use acquisitions of this type as a key method to grow reserves and production because we believe this strategy increases production and cash flow visibility while reducing dry hole and exploration risk. We believe our expertise in the Gulf of Mexico and Gulf Coast region allows us to effectively evaluate acquisitions and to operate the properties we eventually acquire.

Maintain Financial Discipline. We strive to maintain a conservative financial position, sufficient liquidity and a strong balance sheet. We establish our capital spending plans with the goal of funding those costs with cash flows from operations. We currently have access to our senior credit facility (the “Senior Credit Facility”) which we entered into on February 14, 2011. On October 31, 2012, the facility was amended and restated in connection with the Hilcorp Acquisition to increase the aggregate commitment under the Senior Credit Facility from $250 million to a maximum of $750 million and to extend the maturity date to October 31, 2016. In January 2014, our lenders approved a $50 million increase in our borrowing base under our Senior Credit Facility, increasing our borrowing base to $475 million. As of February 21, 2014, we had $265 million in availability under our Senior Credit Facility. In order to maintain financial flexibility, we plan to fund our 2014 fiscal year exploration and development capital budget with cash flow from operations and borrowings under our Senior Credit Facility, as needed. Additionally, because we operate many of our properties, we are able to manage the timing of a substantial portion of our capital investments. We may fund future acquisitions with a combination of cash on hand, borrowings under our Senior Credit Facility and issuances of debt and equity securities under our universal shelf registration statement that became effective under the Securities Act of 1933 in July 2011.

Capitalize on Competency in Plugging and Abandonment. We have established and are executing on a proactive, multi-year plan to plug, abandon and decommission depleted wells and associated infrastructure. Our chairman, president and chief executive officer has significant experience in conducting these types of operations and has supplemented our staff to accomplish this objective. In our East Bay field where our abandonment and decommissioning obligations are concentrated, we have completed plugging and abandonment operations on more than 48% of the inactive wellbores. We expect to reduce our lease operating expense over time by removing idle infrastructure and its associated maintenance costs.

Where You Can Find More Information

We maintain a website at www.eplweb.com that contains information about us, which information is available free of charge, including links to our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all related amendments as soon as reasonably practicable after electronically filing such reports with, or furnishing them to the Securities and Exchange Commission (the "SEC"). In addition, our website contains our Corporate Governance Guidelines and the charters for our Audit, Compensation, Nominating and Governance and Environmental, Health and Safety Committees. Copies of this information are also available by writing to our Corporate Secretary at 201 St. Charles Avenue, Suite 3400, New Orleans, Louisiana 70170. Our website and the information contained in it and connected to it shall not be deemed incorporated by reference into this Annual Report or any other filing that we make with the SEC.

We file Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934 (as amended, the “Exchange Act”). The public may read and copy any materials that we file with the SEC at the SEC’s Public Reference Room at 100 F Street, NE, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file electronically with the SEC. The public can obtain any document we file with the SEC at www.sec.gov.

Properties

As of December 31, 2013, we had working interests in 32 producing fields located in the Gulf of Mexico shelf region. The proved reserves and production from these fields are primarily associated with the following core producing areas: Ship Shoal 208, East Bay, West Delta, South Timbalier, South Pass 78, Main Pass, South Marsh Island 239 and South Pass 49.

During 2013, we concentrated on exploration and exploitation opportunities in the Ship Shoal 208, West Delta, South Pass 78 and Main Pass areas and evaluated certain well proposals in these areas using our recently reprocessed 3-D seismic data.

As of and for the year ended December 31, 2013, our proved reserves and production from our core producing areas as percentages of our total proved reserves and total production were as follows:

	Proved Reserves	Production
Ship Shoal 208	24 %	10 %
East Bay	17	11
West Delta	15	32
South Timbalier	12	8
South Pass 78	10	7
Main Pass	6	8
South Marsh Island 239	4	4
South Pass 49	3	7

Our Ship Shoal 208 complex is located 110 miles southwest of New Orleans. It contains 31 producing wells in average water depths of approximately 100 feet in three lease blocks. We operate the Ship Shoal 208 complex and own a working interest of 100% of the acreage position in this area.

Our East Bay area includes the South Pass 24 and 27 fields and is located 89 miles southeast of New Orleans, near the mouth of the Mississippi River. It contains 197 producing wells located along the coastline and in water depths up to approximately 70 feet. We operate this field and own an average 96% working interest in our acreage position in this area.

Our West Delta complex, a legacy producing area, is located 62 miles south southeast of New Orleans. It contains 44 producing wells in water depths ranging from 29 to 87 feet and includes five lease blocks. We operate the West Delta complex and own an average 93% working interest in our acreage position in this area.

Our South Timbalier area includes the South Timbalier 26 and 41 fields located approximately 60 to 72 miles south of New Orleans. It contains 18 producing wells in water depths of approximately 73 feet or less. We operate the South Timbalier 26 and 41 blocks, and we own a 100% working interest in this area.

Our South Pass 78 complex is located 86 miles southeast of New Orleans. It contains 25 producing wells in water depths ranging from approximately 140 to 190 feet in four lease blocks. We operate the South Pass 78 complex and own a working interest of 67% of the acreage position in this area.

Our Main Pass complex is located 98 miles southeast of New Orleans. It contains 33 producing wells in average water depths of approximately 250 feet and includes the Main Pass 296 and 311 fields. We own a non-operated 50% working interest in our acreage position in this area.

Our South Marsh Island 239 complex is located 117 miles southwest of New Orleans. It contains 9 producing wells in water depths of approximately 20 feet in four lease blocks. We operate the complex and own a working interest of 92% in the acreage position in this area.

Our South Pass 49 field, which is located near our East Bay field contains 6 producing wells in water depths of approximately 285 feet. We own a working interest of 44% of the acreage position in this area.

Our properties include other producing fields offshore Louisiana located in water depths ranging from approximately 18 to 300 feet with working interests ranging from 7% to 100%.

As of December 31, 2013, we also owned interests in 6 undeveloped leases in the deepwater Gulf of Mexico and we have a non-operated interest in one developed lease. Our working interests in our leases in this area ranged from 15% to 33%.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations" for information regarding our oil and gas production, average prices and average costs.

Oil and Natural Gas Reserves

The following table presents our estimated net proved oil and natural gas reserves and the estimated future net revenues and cash flows related to our reserves at December 31, 2013, 2012 and 2011. Our estimates of proved reserves are based on a reserve report prepared as of December 31, 2013 by Netherland, Sewell & Associates, Inc. ("NSAI"), an independent petroleum engineering firm. Neither PV-10 nor the standardized measure of discounted future net cash flows shown in the table is intended to represent the current market value of the estimated oil and natural gas reserves that we own. Note 15 "Supplementary Oil and Natural Gas Disclosures—(Unaudited)" of the consolidated financial statements in Part II, Item 8 of this Annual Report provides important additional information about our proved oil and natural gas reserves.

We follow the oil and gas reserves estimation and disclosure requirements of Accounting Standards Codification ("ASC") Topic 932, "Extractive Activities—Oil and Gas" ("ASC 932"), which requires, among other things, that prices used to estimate reserves for SEC disclosure purposes reflect an unweighted, arithmetic average price based upon the closing price on the first day of each of the twelve months during the fiscal year, rather than the year-end price. See Note 15 "Supplementary Oil and Natural Gas Disclosures—(Unaudited)" of the consolidated financial statements in Part II, Item 8 of this Annual Report for additional information regarding reporting related to oil and natural gas reserves under ASC 932.

	As of December 31,		
	2013	2012	2011
	(dollars in thousands)		
Total net proved reserves:			
Oil (Mbbls)	51,517	47,442	27,301
Natural gas (Mmcf)	173,584	179,939	58,785
Total (Mboe)	80,448	77,432	37,099
Net proved developed reserves (1):			
Oil (Mbbls)	39,439	37,908	24,791
Natural gas (Mmcf)	107,687	120,687	52,739
Total (Mboe)	57,387	58,022	33,581
Net proved undeveloped reserves:			
Oil (Mbbls)	12,078	9,534	2,510
Natural gas (Mmcf)	65,897	59,252	6,046
Total (Mboe)	23,061	19,409	3,518
Estimated future net revenues before income taxes (2)	$ 2,894,227	$ 2,641,407	$ 1,555,059
Present value of estimated future net revenues before income taxes (PV-10) (2)(3)(5)	$ 2,109,324	$ 1,979,274	$ 1,100,701
Standardized measure of discounted future net cash flows (4)(5)	$ 1,649,078	$ 1,574,282	$ 876,169

(1)Net proved developed non-producing reserves as of December 31, 2013 (13,306 Mbbls and 60,875 Mmcf) were 23,452 Mboe, or 29% of our total proved reserves.

(2)Calculated using oil prices of $105.30, $105.13 and $108.48 per barrel, respectively, and natural gas prices of $3.73, $2.92 and $4.16 per Mcf, respectively, held constant for the life of the reserves, computed in accordance with

ASC 932, based on the unweighted, arithmetic average of the closing price on the first day of each of the twelve months during the fiscal year (as required by ASC 932), applying historical adjustments, including transportation, quality differentials, and purchaser bonuses, on an individual property basis, to the year-end quantities of estimated proved reserves. The historical adjustments applied to the computed prices are determined by comparing our historical realized price experience with the comparable historical market, or posted, price.

(3)The present value of estimated future net revenues attributable to our reserves was prepared using constant prices, determined in the manner described in footnote (2), discounted at a rate of 10% per year on a pre-tax basis.

(4)The standardized measure of discounted future net cash flows represents the present value of future cash flows after income taxes discounted at 10% per year, as calculated in accordance with SEC guidelines and pricing.

(5)PV-10 is considered a non-GAAP financial measure as defined by the SEC. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after-tax amount, because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. Because the standardized measure is dependent on the unique tax situation of each company, our calculation may not be comparable to those of our competitors. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis.

As of December 31, 2013, our PUDs comprised 37 drilling locations in 13 fields. The Ship Shoal 208 field accounts for approximately 50% of our total PUDs, with 11,495 Mboe, consisting of 6,579 Mbbls of oil and 29,496 Mmcf of natural gas. The remaining 12 locations account for approximately 1% to 8% of our total PUDs each, with PUDs ranging from 156 Mboe to 1,959 Mboe.

For the year ended December 31, 2013, the increase in our PUDs was primarily attributable to extensions and discoveries resulting in approximately 7,895 Mboe of proved reserves associated with 12 drilling locations. The Ship Shoal 208 field accounts for approximately 53% of our PUD extensions and discoveries with 4,152 Mboe, consisting of 3,541 Mbbls of oil and 3,668 Mmcf of natural gas in 5 locations. The remainder of our PUD extensions and discoveries were in five other fields with PUD extensions and discoveries ranging from 110 Mboe to 1,299 Mboe. During the year ended December 31, 2013, we divested 179 Mboe of PUDs in the Bay Marchand field and drilled two PUD locations in the West Delta area and one in the Ship Shoal 208 field. The three drilled PUD locations represent 1,675 Mboe, or approximately 9%, of our PUDs at December 31, 2012, consisting of 1,515 Mbbls of oil and 961 Mmcf of natural gas. We spent approximately $52 million drilling these three locations.

For the year ended December 31, 2012, the acquisition of the Hilcorp Properties added PUDs of 15,472 Mboe. Other changes in our PUDs that occurred during the year ended December 31, 2012 were considered individually insignificant, netting to an increase of 419 Mboe.

We expect our PUDs as of December 31, 2013 of 23.1 Mmboe to begin converting from proved undeveloped to proved developed as the planned development projects begin in 2014. We project future development costs relating to the development of the PUDs remaining at December 31, 2013 to be approximately $229 million in 2014, $52 million in 2015, $5 million in 2016 and $23 million thereafter.

Our Vice President, Reserves, is the technical person primarily responsible for overseeing the preparation of our reserve estimates and for compliance with our policies. He is a registered petroleum engineer with extensive experience in reservoir analysis and reports directly to our executive management. At the end of each year, our reserve estimates are prepared by outside petroleum engineering firms. As of December 31, 2013, our estimates of proved reserves are based on a reserve report prepared by the independent petroleum engineering firm NSAI, a nationally recognized engineering firm. At December 31, 2013, estimates of 100% of our total estimated net proved reserves were prepared by NSAI. NSAI's report is filed as an exhibit to this Annual Report on Form 10-K.

NSAI provides a complete range of geological, geophysical, petrophysical and engineering services and have the technical experience and ability to perform these services in any of the onshore and offshore oil and gas producing areas of the world. NSAI has a technical staff of over 70 professionals who are knowledgeable with regard to recognized industry reserves and resource definitions, specifically those set forth by the SEC. NSAI's report includes a description of the technical qualifications of the individuals at NSAI primarily responsible for preparing our reserve estimates.

We have internal controls in place to provide reasonable assurance of compliance with SEC rules in the determination of our reserve estimates. These controls include:

•corporate policies which require reserve estimates to be in compliance with SEC guidelines;

•data on new discoveries is reviewed by the Vice President, Reserves, and our outside engineering firm for evaluation and incorporation into our reserve estimates;

•year-end reserve estimates are reviewed by our Vice President, Reserves, and our chief executive officer and other senior management; and

•revisions are communicated to our board of directors.

As an operator of domestic oil and gas properties, we have filed Department of Energy Form EIA-23, "Annual Survey of Oil and Gas Reserves," as required by Public Law 93-275. The differences between the reserves as reported on Form EIA-23 and those reported herein are attributable to the fact that Form EIA-23 requires that an operator report the total reserves attributable to wells that it operates, without regard to percentage ownership and excluding non-operated wells in which it owns an interest.

The table below sets forth production information for each field that contains 15% or more of our total proved reserves as of December 31, 2013. The Ship Shoal 208 field was acquired in the Hilcorp Acquisition and the table below reflects production for this field beginning November 1, 2012.

	Year Ended December 31,		
	2013	2012	2011
Ship Shoal 208:			
Oil (Mbbls)	658	109	-
Natural gas (Mmcf)	1,130	199	-
Total (Mboe)	846	142	-
East Bay:			
Oil (Mbbls)	879	1,035	1,062
Natural gas (Mmcf)	90	47	76
Total (Mboe)	894	1,043	1,075
West Delta:			
Oil (Mbbls)	2,293	1,142	775
Natural gas (Mmcf)	2,000	490	317
Total (Mboe)	2,626	1,224	828

Costs Incurred in Oil and Natural Gas Activities

The following table sets forth the costs incurred associated with finding, acquiring and developing our proved oil and natural gas reserves.

	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Acquisitions—Proved (1)	$ 46,047	$ 706,322	$ 261,812
Acquisitions—Unproved	2,200	7,496	14
Exploration	46,100	43,338	17,129
Development (2)	303,245	180,938	83,577
Costs incurred	$ 397,592	$ 938,094	$ 362,532

(1)For the year ended December 31, 2013, includes $30 million associated with the acquisition of the Hilcorp Properties and $17 million associated with the acquisition of the WD29 Interests. See Note 2 “Acquisitions and Dispositions” of the consolidated financial statements in Part II, Item 8 of this Annual Report for further information.

(2)Includes our estimates during the years ended December 31, 2013, 2012 and 2011 of incurred asset retirement obligations associated with finding and developing our proved oil and natural gas reserves of $1.2 million, $1.2 million and $0.2 million, respectively.

Productive Wells

The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2013.

	Total Productive Wells	
	Gross	Net
Oil	379	314
Natural gas	98	72
Total	477	386

Productive wells consist of producing wells and wells capable of production, including oil wells awaiting connection to production facilities and natural gas wells awaiting pipeline connections to commence deliveries. Thirty-seven gross oil wells and 11 gross natural gas wells have dual completions.

In this Annual Report, when referring to wells and acreage, “gross” refers to the total wells or acres in which we have a working interest and “net” refers to gross wells or acres multiplied by our working interest.

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Acreage

The following table sets forth information relating to acreage held by us as of January 15, 2014. Developed acreage is assigned to producing wells.

	Gross Acreage	Net Acreage
Developed:		
Gulf of Mexico Shelf	319,375	237,659
Deepwater Gulf of Mexico	5,760	1,599
Other	125	125
Total	325,260	239,383
Undeveloped:		
Gulf of Mexico Shelf	62,245	60,422
Deepwater Gulf of Mexico	34,560	9,663
Total	96,805	70,085

We continually assess our undeveloped lease inventory for exploration opportunities and, where appropriate, develop strategies to maintain our inventory by allocating resources to such leases or arranging for the participation of others, including farm-outs and the use of prospect generation consulting geologists. Leases covering 14% of our undeveloped net acreage expire in 2014, 8% expire in 2015, 10% expire in 2016, 39% expire in 2017, and 21% expire in 2018. The remaining undeveloped net acreage is held by production. We currently plan to develop opportunities for leases covering 48% of the net undeveloped acreage expiring in 2014. As of December 31, 2013, the total net book value of the leases expiring in 2014 and 2015 was $0.2 million.

Since December 31, 2012, our net developed acreage decreased 4,589 net acres, or 2%, and our net undeveloped acreage decreased 53,823 net acres, or 43%. The decrease in our net developed acreage was primarily attributable to a decrease of 36,275 net acres, or 15%, associated with certain Gulf of Mexico shelf leases that expired or were relinquished, which was substantially offset by an increase of 31,759 net acres, or 13%, primarily due to the Nexen Acquisition and the development of certain leases in our West Delta and Main Pass fields. The decrease in our net undeveloped acreage was primarily attributable to decreases totaling 69,642 net acres, or 56%, primarily associated with certain undeveloped Gulf of Mexico shelf and deepwater Gulf of Mexico leases that expired or were relinquished. The decrease was partially offset by the acquisition of new Gulf of Mexico shelf leases totaling 15,819 net acres, or 13%, resulting from recent federal lease sales.

Drilling Activity

Drilling activity refers to the number of wells completed at any time during the applicable fiscal years, regardless of when drilling was initiated. The following table shows our drilling activity where “gross” refers to the total wells in which we have a working interest and “net” refers to gross wells multiplied by our working interest in these wells.

	Year Ended December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	13.0	11.5	11.0	9.5	4.0	3.6

Non-productive	3.0	3.0	1.0	1.0	1.0	1.0
Total	16.0	14.5	12.0	10.5	5.0	4.6
Exploratory Wells						
Productive	-	-	1.0	0.8	4.0	1.3
Non-productive	1.0	1.0	2.0	0.7	1.0	0.5
Total	1.0	1.0	3.0	1.5	5.0	1.8
Recompletion Operations						
Productive	17.0	14.4	16.0	14.2	23.0	19.1
Non-productive	4.0	3.7	2.0	2.0	4.0	3.3
Total	21.0	18.1	18.0	16.2	27.0	22.4

We also drilled one gross (1.0 net) successful exploratory oil well in a recently-acquired primary term lease in our Main Pass 244 field that reached its target depth in September 2013 and is waiting on production facilities to commence production.

We are currently in the process of drilling five gross (5.0 net) development wells, three in our Ship Shoal 208 field, one in our West Delta area and one in our South Timbalier area. In addition, we recently drilled one exploratory well (0.5 net) in our Ship Shoal 208 field, which we are completing and anticipate first production in April 2014.

Title to Properties

Our properties are subject to customary royalty interests, liens under indebtedness, liens incident to operating agreements, mechanics' and materialman's liens, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interfere with the use of our properties or the operation of our business.

We believe that we have satisfactory title to, or rights in, all of our properties. As is customary in the oil and natural gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. We investigate title prior to the consummation of an acquisition of producing properties and before the commencement of drilling operations on undeveloped properties. We have obtained or conducted a thorough title review on substantially all of our producing properties and believe that we have satisfactory title to such properties in accordance with standards generally accepted in the oil and natural gas industry.

Regulatory Matters

Our operations are substantially affected by federal, state and local laws and regulations. In particular, oil and gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing crude oil and natural gas properties have statutory provisions regulating the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Regulation of Natural Gas Gathering. Section 1(b) of the Natural Gas Act of 1938, as amended (the "NGA"), exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission ("FERC") as a natural gas company under the NGA. We believe that our natural gas pipelines and appurtenant facilities meet the tests the FERC has historically used to establish a facility's status as a gathering facility not subject to regulation as a natural gas company under the NGA. However, the distinction between FERC-regulated transmission facilities and federally unregulated gathering facilities is the subject of on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by the FERC, the courts, or Congress. Natural gas gathering facilities and operations may, at some point in the future, receive greater regulatory scrutiny at both the state and federal levels. Our natural gas gathering operations could be adversely affected should they be subject to more stringent application of state or federal regulation of rates and services. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Regulation of Offshore Gathering Facilities. Our gathering systems gather gas and oil on the Outer Continental Shelf (the “OCS”) and in Louisiana. Our gathering systems are subject to the jurisdiction of the applicable state regulatory agencies to the extent that those gathering systems traverse state land and/or waters. State regulation of gathering facilities generally includes a variety of safety, environmental, nondiscriminatory take, and common purchaser requirements, and complaint-based rate regulation.

The gathering systems are also subject to the jurisdiction of the Bureau of Ocean Energy Management (“BOEM”) and the Bureau of Safety and Environmental Enforcement (“BSEE”), pursuant to The Outer Continental Shelf Lands Act (“OCSLA”), because they traverse the OCS pursuant to federal easements. As discussed herein, the BOEM and BSEE were created on October 1, 2011 to replace the Bureau of Ocean Energy Management, Regulation and Enforcement (“BOEMRE”) as part of a reorganization aimed at separating the resource management and enforcement functions of the former Minerals Management Service. OSCLA authorizes regulations governing the preparation of spill contingency plans and establishing air quality standards for certain pollutants, including particulate matter, volatile organic compounds, sulfur dioxide, carbon monoxide and nitrogen oxides. Specific design and operational standards may apply to outer continental shelf vessels, rigs, platforms, vehicles and structures. Violations of lease conditions or regulations related to the environment issued pursuant to

OCSLA can result in substantial civil and criminal penalties, as well as potential court injunctions curtailing operations and canceling leases. Such enforcement liabilities can result from either governmental prosecution or private action.

Regulation of Onshore Gathering Facilities. Our onshore natural gas gathering operations are subject to ratable take and common purchaser statutes in the states in which we operate. The common purchaser statutes generally require our gathering pipelines to purchase or take without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another. The regulations under these statutes can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. Louisiana and Texas have adopted a complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering access and rate discrimination. The rates we charge for gathering in Texas and Louisiana are deemed just and reasonable unless challenged in a complaint. We cannot predict whether such a complaint will be filed against us in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal penalties.

Though our natural gas gathering facilities are not subject to regulation by the FERC under the NGA, as the owner and operator of these facilities, we may be subject to certain annual natural gas transaction reporting requirements and daily scheduled flow and capacity posting requirements imposed by FERC depending on the volume of natural gas transactions and flows on our facilities in a given period. See the discussion of "—Other Federal Laws and Regulations Affecting Our Industry—FERC Market Transparency Rules."

Regulation of Sales of Natural Gas and Natural Gas Liquids ("NGLs"). The price at which we buy and sell natural gas and NGLs is currently not subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical purchases and sales of these energy commodities, and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Future Trading Commission ("CFTC"). See below the discussion of "—Other Federal Laws and Regulations Affecting Our Industry—Energy Policy Act of 2005." Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities. In addition, some of our operations may be required to annually report to the FERC, information regarding natural gas purchase and sale transactions depending on the volume of natural gas purchased or sold during the prior calendar year. See below the discussion of "—Other Federal Laws and Regulations Affecting Our Industry—FERC Market Transparency Rules."

Regulation of Safety, Availability, Terms and Cost of Pipeline Transportation. Our onshore and offshore pipelines are subject to safety regulation by the Pipeline and Hazardous Materials Administration of the U.S. Department of Transportation (the "PHMSA"), BSEE and/or state agencies, depending on the location and services provided by each pipeline. Our processing operations and our marketing of natural gas and NGLs are affected by the availability, terms and cost of pipeline transportation. The price and terms of access to pipeline transportation can be subject to extensive federal and, if a complaint is filed, state regulation. The FERC regularly proposes and implements new rules and regulations affecting the interstate transportation of natural gas, and to a lesser extent, the interstate transportation of NGLs. We cannot predict the ultimate impact of these regulatory changes to our natural gas production operations and our natural gas and NGL marketing operations. We do not believe that we would be affected by any such FERC action in a materially different manner than other natural gas producers and natural gas and NGL marketers with whom we compete.

The ability of our facilities to deliver natural gas into third party natural gas pipeline facilities is directly impacted by the gas quality specifications required by those pipelines. In 2006, the FERC issued a policy statement on provisions governing gas quality and interchangeability in the tariffs of interstate gas pipeline companies and a separate order declining to set generic prescriptive national standards. In its policy statement on gas quality and interchangeability, the FERC encouraged all natural gas pipelines subject to its jurisdiction to use certain interim guidelines issued by a group of industry representatives, headed by the Natural Gas Council (the “NGC+ Work Group”), as the common reference point for resolving gas quality and interchangeability issues. We do not believe that the adoption of gas quality and interchangeability standards that are in line with the NGC+ Work Group’s interim guidelines by a pipeline that either directly or indirectly interconnects with our facilities would materially affect our operations. We cannot predict, however, whether FERC will approve gas quality specifications that materially differ from the NGC+ Work Group’s interim guidelines for such an interconnecting pipeline.

Regulation of Transportation of Oil. Our wholly owned subsidiary, EPL Pipeline, L.L.C. (“EPL Pipeline”), is an interstate common carrier pipeline subject to regulation by the FERC under the Interstate Commerce Act (“ICA”). EPL Pipeline owns five pipelines subject to regulation by the FERC: (1) an approximately twelve-mile pipeline that runs between South Timbalier 26 and a portion of South Timbalier 41 on the Gulf of Mexico OCS to Bayou Fourchon, Louisiana; (2) an approximately eight-mile pipeline that runs between South Marsh Island Block 239 through Mound Point B and South Marsh Island Block 205 to Lighthouse Point A, South Marsh Island Block 207 on the Gulf of Mexico OCS to Vermillion Parish, Louisiana; (3) an approximately nine-mile pipeline that runs between South Pass Block 78 and South Pass Block 55 on the

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Gulf of Mexico OCS; and (4) an approximately ten-mile pipeline that runs between South Pass Block 55 and West Delta Block 83 on the Gulf of Mexico OCS to Plaquemines Parish, Louisiana; and (5) an approximately ten-mile pipeline that runs between Vermillion Block 38 to a point of interconnection designated as the EPL Pipeline Vermillion Block 38 Lateral Interconnect. The ICA requires that we maintain tariffs on file with the FERC for these pipelines. The tariffs set forth the rates, which were established as negotiated rates that have not been protested, as well as the rules and regulations governing these services. The ICA requires, among other things, that rates on interstate common carrier pipelines be “just and reasonable” and nondiscriminatory. The ICA permits challenges to existing rates and authorizes the FERC to investigate such rates to determine whether they are just and reasonable. If a challenge is made to a newly filed increased rate and FERC ultimately finds that the proposed rate is unlawful following an investigation, FERC is permitted to change that rate prospectively from the date of its decision, and may order refunds representing the difference between the challenged increased rate and the previous lawful rate. If a complaint is filed against an existing rate, FERC may award reparations for the two year period prior to the date of the complaint.

Other Federal Laws and Regulations Affecting Our Industry

Energy Policy Act of 2005. The Energy Policy Act of 2005 (“EPAct 2005”) is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. With respect to regulation of natural gas transportation, EPAct 2005 amended the NGA by increasing the criminal penalties available for violations of each Act. EPAct 2005 also added a new section to the NGA that provides the FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce, including our Company. EPAct 2005 also amended the NGA to add an anti-market manipulation provision that makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by the FERC. FERC’s regulations make it unlawful to: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit any statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any entity. The regulations do not directly apply to activities that relate only to non-jurisdictional sales or gathering, but do apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities (including those which engage in non-jurisdictional sales or gathering) to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements and daily scheduled flows.

FERC Market Transparency Rules. FERC’s regulations require wholesale buyers and sellers of more than 2.2 MmBtu of physical natural gas in the previous calendar year (including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors and natural gas marketers) to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such actions on a materially different basis than other natural gas companies with whom we compete.

Environmental Matters

General. Various federal, state and local laws and regulations governing the protection of the environment, such as the Oil Pollution Act of 1990 (“OPA”), the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended (“CERCLA”), the Resource Conservation and Recovery Act, as amended (“RCRA”), the Federal Water

Pollution Control Act of 1972, as amended (the "Clean Water Act"), and the Federal Clean Air Act, as amended (the "Clean Air Act"), affect our operations and costs. In particular, our exploration, development and production operations, our activities in connection with storage and transportation of oil and other hydrocarbons, and our use of facilities for treating, processing or otherwise handling hydrocarbons and related wastes may be subject to regulation under these and similar state laws and regulations. These laws and regulations:

- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities and establish requirements for the management and disposal of drill production water and wastes;

- limit or prohibit drilling and production activities on certain lands lying within wetlands and other protected areas and in ways that affect certain species;

- impose permitting, monitoring, and recordkeeping requirements and other regulatory controls; and

•impose substantial liabilities, including cleanup obligations, for pollution and natural resource damages resulting from our operations.

Failure to comply with these laws and regulations could result in the assessment of significant administrative, civil and criminal fines and penalties, the incurrence of capital expenditures, delays in the development of projects, the imposition of remedial or corrective action obligations, or injunctive relief that could include limitations on, or the cessation of, certain of our operations. Changes in environmental laws and regulations occur regularly and the current trend is toward more stringent environmental regulation and legislation. We believe that we are in substantial compliance with currently applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us. For example, we did not incur any material capital expenditures for remediation or pollution control activities for the year ended December 31, 2013, and we are not aware of any environmental issues or claims that will require material capital expenditures during 2014. Nevertheless, accidental spills or releases may occur in the course of our operations, and we cannot give any assurances that we will not incur substantial costs and liabilities, as a result of such spills or releases, which would not be covered by insurance, including those relating to claims for damage to property and persons. Moreover, we cannot give any assurance that the passage of more stringent or additional laws or regulations in the future will not materially adversely affect our business, results of operations and financial condition.

Oil Pollution Act of 1990. The OPA, and regulations thereunder, impose significant liability on “responsible parties” for removal costs and damages resulting from oil spills into or upon navigable waters, adjoining shorelines, or in the exclusive economic zone of the United States, including the OCS waters where we have substantial operations. A “responsible party” includes the owner or operator of an onshore facility and the lessee or permittee of the area in which an offshore facility is located. OPA also requires that the lessee or permittee of the offshore area in which a covered offshore facility is located establish and maintain evidence of financial responsibility in the amount of $35.0 million ($10.0 million if the offshore facility is located landward of the seaward boundary of a state) to cover liabilities related to an oil spill for which such person is statutorily responsible. The amount of required financial responsibility may be increased above the minimum amounts to an amount not exceeding $150.0 million depending on the risk represented by the quantity or quality of oil that is handled by the facility. We carry insurance coverage to meet these obligations, which we believe is customary for comparable companies in our industry.

A failure to comply with OPA’s requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions, including penalties and natural resource damages.

We are not aware of the occurrence of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA’s current financial responsibility and other operating requirements will not have a material adverse effect on us.

Superfund. CERCLA, also known as Superfund, and comparable state laws impose strict liability for response costs associated with releases of “hazardous substances” and damages to natural resources as a result of such releases, without regard to fault or the legality of the original act, on certain classes of persons. These persons include the current or former “owner” or “operator” of a disposal site or a site where a release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site.

While the term “hazardous substance” under CERCLA does not include petroleum, natural gas, NGLs, liquefied natural gas, or synthetic gas usable for fuel, we may generate wastes that fall within CERCLA’s definition of a “hazardous substance” in the course of our ordinary operations. We also own or lease properties that for many years have been used for the exploration and production of oil and natural gas. Although we and, to our knowledge, our predecessors have used operating and disposal practices that were standard in the industry at the time, we may still be responsible if “hazardous substances” were disposed or released on, under or from these properties or on, under or from other locations where these wastes have been taken for disposal. CERCLA authorizes the federal Environmental Protection Agency (“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 from responsible parties the costs they incur. At this time, we do not believe that we have any liability associated with any Superfund site, and we have not been notified of any claim, liability or damages under CERCLA.

Resource Conservation and Recovery Act. RCRA and comparable state laws impose detailed requirements relating to the handling, storage, treatment and disposal of hazardous waste. We routinely generate small quantities of hazardous waste in the ordinary course of our business that are subject to these requirements. These wastes are treated, stored and disposed of off-site at facilities that are permitted to manage them. At present, RCRA and many similar state statutes include a statutory exemption that allows most oil and natural gas exploration and production waste to be classified as nonhazardous waste. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and natural gas exploration and production wastes from regulation as hazardous waste. Repeal or modification of the current exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses.

Clean Water Act. The Clean Water Act imposes restrictions and controls on the discharge of pollutants, including petroleum, produced water and other certain wastes into navigable waters, including coastal waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or, to a lesser degree, developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for significant civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants or unauthorized discharges of pollutants or fill material into wetlands or other waters. These statutes also impose liability for cleanup, restoration and damages on the parties responsible for those discharges. We are subject to the Clean Water Act's permitting requirements for discharges associated with exploration and development activities. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

Safe Drinking Water Act. The underground injection of oil and natural gas wastes are regulated by the Underground Injection Control Program, authorized by the Safe Drinking Water Act. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. In Louisiana and Texas, no underground injection may take place except as authorized by permit or rule. We currently own and operate various underground injection wells. Failure to comply with our permits could subject us to civil and/or criminal enforcement. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

National Marine Sanctuary Act, Marine Mammal Protection Act, Migratory Bird Treaty Act, and Endangered Species Act. Certain federal laws, including the National Marine Sanctuary Act, the Marine Mammal Protection Act, the Migratory Bird Treaty Act and the Endangered Species Act, provide special protection to certain designated marine areas and marine species. These laws and their state equivalents provide for significant civil and criminal penalties for unpermitted activities that result in harm to or harassment of certain protected plants and animals, including damage to their habitats. Further, if such species are located in an area in which we conduct operations, our operations could be prohibited, restricted, or delayed, or we could be required to implement expensive mitigation measures.

In addition, Executive Order 13158 (Marine Protected Areas), issued in 2000, directs federal agencies to strengthen existing Marine Protected Areas ("MPAs"), establishes new MPAs, and develops a national system of MPAs. This order could adversely affect our operations by restricting areas in which we may carry out future exploration or production activities and/or cause us to incur increased operating expenses. In addition, federal permit approvals are conditioned on the collection and removal of debris resulting from activities related to exploration, development and production of offshore leases in order to prevent harm to marine species. The BSEE also issues Notices to Lessees and Operators ("NTLs") that provide guidance on the implementation of and compliance with OCSLA regulations. Many of these NTLs, with which we must comply, relate to the prevention of harm to marine species.

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operations frequently require federal licenses, permits, and/or other governmental approvals. Several federal statutes, including OCSLA, the National Environmental Policy Act, and the Coastal Zone Management Act require federal agencies to evaluate environmental issues in connection with granting such approvals and/or taking other major agency actions. The environmental review process required under these laws can be costly and time-consuming, are increasingly the subject of citizen group intervention and challenge, and could result in the delay or prohibition of our planned activities.

Lead-Based Paints. Various pieces of equipment and structures owned by us have been coated with lead-based paints as was customary in the industry at the time these pieces of equipment were fabricated and constructed. These paints may contain lead at a concentration high enough to be considered a regulated hazardous waste when removed. If we need to remove such paints in connection with maintenance or other activities and they qualify as a regulated hazardous waste, this would increase the cost of disposal. High lead levels in the paint may also require us to institute certain administrative and/or engineering controls required by the Occupational Safety and Health Act and the BSEE to ensure worker safety during paint removal.

Clean Air Act. Our operations utilize equipment that emits air pollutants subject to the federal Clean Air Act and state air pollution control laws. These laws limit the emissions of regulated pollutants from such equipment and, in some instances, require the installation and operation of pollution control equipment to achieve these emissions limitations and meet ambient air quality standards. These laws also require us to maintain operating permits for existing equipment and obtain construction permits for new and modified equipment. EPA continues to consider and promulgate new or revised regulations under the Clean Air Act, such as the recently revised New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants applicable to the oil and gas industry sector, that generally impose more stringent regulations upon aspects of our business. We could be required to incur costs in the future to make operational changes or to purchase additional air pollution control equipment in order to comply with these changing regulations, although we do not believe that such requirements will have a material adverse effect on our operations. We believe that we are in compliance in all material respects with currently applicable air pollution control laws and requirements.

Climate Change. Scientific studies have suggested that emissions of certain “greenhouse gases,” including carbon dioxide and methane, may be contributing to warming of the Earth’s atmosphere. International negotiations to address climate change have occurred in response to such studies. In 2009, the United States submitted a non-binding greenhouse gas emission reduction target of 17 percent compared to 2005 levels pursuant to the Copenhagen Accord and negotiations continue under the United Nations Framework Convention on Climate Change. In the United States, Congress has considered legislation to reduce emissions of greenhouse gases; however, no such legislation has been passed. It is uncertain at this time whether, and in what form, federal climate change legislation will be adopted.

In the absence of over-arching federal climate change legislation, many states are regulating greenhouse gas emissions. Certain states, either individually or through multi-state regional initiatives, have passed laws, adopted regulations or undertaken regulatory activity to reduce emissions of greenhouse gases.

The EPA is also regulating greenhouse gas emissions from both mobile and certain large stationary sources under its existing authority pursuant to the Clean Air Act. In 2009, the EPA published its finding that greenhouse gases contribute to air pollution that may endanger public health or welfare. Thereafter, the EPA promulgated regulations requiring that major sources in the United States collect and report information regarding greenhouse gas emissions. For petroleum and natural gas facilities, including offshore petroleum and natural gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year, data collection began on January 1, 2011 and the first annual reports were due on March 31, 2012. In January 2011, new EPA permitting requirements became effective for greenhouse gas emissions from new and modified large stationary sources.

Courts are addressing climate change issues as well. Many of the EPA’s greenhouse gas rules are undergoing legal challenges and numerous other challenges are being filed by groups seeking additional regulation of a variety of additional sources of greenhouse gas emissions. On June 20, 2011, the U.S. Supreme Court issued a decision that bars state and private parties from bringing federal common law nuisance actions against certain energy companies based on their alleged contribution to climate change. The Supreme Court’s decision did not, however, address state law claims. This decision is expected to affect pending and future federal climate change cases. Although we are not currently a party to such litigation, we are monitoring these developments.

It is not possible at this time to predict what new regulations may be promulgated to address greenhouse gas emissions or how the promulgation of any such regulations would impact our business. However, any new federal, regional or state restrictions on emissions of greenhouse gases imposed in areas in which we conduct business could result in increased compliance costs or additional operating restrictions, which could have a material adverse effect on our business and the demand for the oil and natural gas we produce.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher greenhouse gas emitting energy sources such as coal, our products would become more desirable in the market with more stringent limitations on greenhouse gas emissions. To the extent that our products are competing with lower greenhouse gas emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on greenhouse gas emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations.

Scientific studies on climate change suggest that stronger storms may occur in the future in the areas where we operate, although the scientific studies are not unanimous. Due to their location, our operations in the Gulf of Mexico are vulnerable to operational and structural damages resulting from hurricanes and other severe weather systems and our insurance may not cover all associated losses or may become more difficult or expensive to secure if such storms occur with increasing frequency. As discussed below in “Plugging, Abandonment and Decommissioning,” we are taking steps to mitigate physical risks from storms, but no assurance can be given that future storms will not have a material adverse effect on our business.

Naturally Occurring Radioactive Materials (“NORM”). NORM are materials whose radioactivity is enhanced by technological processing such as mineral extraction or processing through exploration and production conducted by the oil and natural gas industry. NORM wastes are regulated under the RCRA framework, but primary responsibility for NORM regulation has been a state function. Standards have been developed for worker protection; treatment, storage and disposal of NORM waste; management of waste piles, containers and tanks; and limitations upon the release of NORM-contaminated land for unrestricted use. We believe that our operations are in material compliance with all applicable NORM standards.

Offshore Leasing and Permitting. Offshore operations, including engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells, and facility removals, were formerly regulated by BOEMRE. On October 1, 2011, the U.S. Department of the Interior completed its reorganization of the BOEMRE (formerly the Minerals Management Service) by the creation of three independent agencies, each with its own offshore oil and gas responsibilities: the BOEM, with responsibility for leasing and environmental studies; the BSEE, with responsibility for field operations, including inspections, regulatory compliance, and oil spill response; and a third agency for management of revenues. The BOEMRE now ceases to exist. At this time, we believe that our operations are in material compliance with applicable regulations and orders. We cannot predict, however, the impact that the BOEMRE reorganization, or future regulations or enforcement actions taken by the new agencies, may have on our operations.

Plugging, Abandonment and Decommissioning. We are responsible for plugging and abandoning wellbores and decommissioning associated platforms, pipelines and facilities on our oil and natural gas properties. Some of our offshore operations are conducted on federal leases that are administered by the BOEM and are required to comply with the regulations and orders promulgated by the BOEM and BSEE under OCSLA.

We are subject to an active NTL, effective October 15, 2010, on the decommissioning of wells and platforms. The NTL imposes more stringent requirements for decommissioning facilities that pose a hazard to safety or the environment, as well as for facilities that are not useful for lease operations and that are not capable of oil and natural gas production in “paying quantities.” Historically, approval was granted to operators to maintain these structures in order to conduct future activities. However, the NTL significantly restricts this practice. Under the NTL, lessees must submit an application to permanently plug any well that poses a hazard to safety or the environment within 30 days after identifying the hazard. The NTL also imposes new deadlines for removing platforms or other facilities that are no longer useful for operations. Furthermore, the NTL imposes new deadlines for plugging, abandoning or performing downhole zonal isolation on wells that are no longer useful for operations and that are no longer capable of production in paying quantities. In May 2013, we responded to a written request from BOEM for information on our “idle iron” issues by submitting a company-wide three-year plan for our wellbore plugging and abandonment and decommissioning activities through 2016.

The effects of Hurricanes Katrina and Rita during the 2005 hurricane season and Hurricanes Ike and Gustav in 2008 significantly impacted oil and gas operations on the OCS. The effects included structural damage to fixed production facilities, semi-submersibles and jack-up drilling rigs. Both the BOEM and the BSEE are concerned about the potential for catastrophic damage to key infrastructure and the resultant pollution from future storms. In an effort to reduce the potential for future damage, the former BOEMRE issued still active guidance through NTLs, aimed at improving platform survivability by taking into account environmental and oceanic conditions in the design of platforms and related structures. It is possible that similar, if not more stringent, design and operational requirements will be issued by the BOEM or BSEE in the future and these new requirements could increase our operating costs. The BOEM, BSEE and other regulatory bodies, including those regulating the decommissioning of our pipelines and facilities under the jurisdiction of the state of Louisiana, may change their requirements or enforce requirements in a manner inconsistent with our expectations, which could materially increase the cost of such activities and/or accelerate the timing of cash expenditures and could have a material adverse effect on our financial position, results of operations and cash flows.

The failure to comply with these rules and regulations could result in substantial penalties, including lease termination in the case of federal leases. Under limited circumstances, the BSEE could require us to suspend or terminate our operations on a federal lease or we could have difficulty entering into new leases in the future. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations, although the impact of those requirements may vary significantly based on the nature and location of operations and related pipelines and facilities.

Significant Customers

We market substantially all of our oil and natural gas production. We sell our natural gas to marketing companies pursuant to a variety of contractual arrangements, generally under contracts with terms no longer than six to twelve months. Pricing on those contracts is based largely on published regional index pricing. We sell our oil under contracts with month-to-month terms to a variety of purchasers. The pricing for oil is based upon the posted prices set by major purchasers in the production area, reporting publications, or upon New York Mercantile Exchange ("NYMEX") pricing. Oil pricing is adjusted for quality and transportation differentials. Oil and natural gas purchasers are selected on the basis of price, credit quality and service reliability.

Our oil, condensate and natural gas production is sold to a variety of purchasers, historically at market-based prices. We believe that the prices for liquids and natural gas are comparable to market prices in the areas where we have production. Of our total oil and natural gas revenues in 2013, Chevron USA, Inc. accounted for approximately 63%, ConocoPhillips accounted for approximately 24%, and Shell Trading (US) Company accounted for approximately 6%. Due to the nature of the markets for oil and natural gas, we do not believe that the loss of any one of these customers would have a material adverse effect on our financial condition or results of operations, although a temporary disruption in production revenues could occur.

Employees

As of December 31, 2013, we had 188 full-time employees, including 39 geoscientists, engineers and technicians and 94 field personnel. Our employees are not represented by any labor union or other collective bargaining organization. We consider relations with our employees to be satisfactory and we have never experienced a work stoppage or strike. We regularly use independent consultants and contractors to perform various professional services in various areas, including in our exploration and development operations, production operations and certain administrative functions.

Competitors

Our competitors include numerous independent oil and gas companies and major oil companies. Many of our larger competitors possess and employ financial and personnel resources substantially greater than ours. These competitors are able to pay more for productive oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to replace and expand our reserve base depends on our ability to attract and retain qualified personnel and identify and acquire suitable producing properties and prospects for future drilling. See Part I, Item 1A, “Risk Factors,” for additional information about risks related to our competitors, personnel and ability to acquire producing properties and prospects.

Seasonality

Historically, the demand for and price of natural gas generally trends upward during the winter months and downward during the summer months. However, these seasonal fluctuations can be interrupted due to summer storage practices where pipeline companies, utilities, distribution companies and industrial users may purchase and place into storage facilities a portion of their anticipated winter requirements of natural gas. These trends are also disrupted by extreme market impacts such as those that occurred in 2008, when oil and natural gas prices reached peak levels in the summer months, then fell during the winter. Tropical storms and hurricanes generally occur in the Gulf of Mexico during late summer and fall, which may require us to evacuate personnel and shut-in production during those periods. The winds and turbulent current conditions that occur in the winter months can impact our ability to safely load, unload and transport personnel and equipment, and perform operations, including plugging, abandonment and other decommissioning activities, which can delay our operations, increase the cost of our operations and/or delay the restoration and maintenance of our oil and natural gas production.

Cautionary Statement Concerning Forward Looking Statements

This Annual Report contains forward-looking statements within the meaning of, and we intend that such forward-looking statements be subject to the safe harbor provisions of, the U.S. federal securities laws. Forward-looking statements are, by definition, statements that are generally not historical in nature and relate to possible future events. They may be, but are not necessarily, identified by words such as “will,” “would,” “should,” “likely,” “estimates,” “thinks,” “strives,” “may,” “anticipates,” “expects,” “believes,” “intends,” “goals,” “plans,” or “projects” and simi

These forward-looking statements reflect our current views with respect to possible future events, are based on various assumptions and are subject to risks and uncertainties. These forward-looking statements are not guarantees or predictions of our future performance, and our actual results and future developments may differ materially from those projected in, and contemplated by, the forward-looking statements. As a result, you should not place undue reliance on these forward-looking statements. Our actual results could differ materially from those anticipated in these forward-looking statements. Among the factors that could cause actual results to differ materially are the risks and uncertainties described under Part I, Item 1A, “Risk Factors,” including the following:

- planned and unplanned capital expenditures;

•adequacy of capital resources and liquidity including, but not limited to, access to additional capacity under our Senior Credit Facility;

•volatility in oil and natural gas prices;

•volatility in the financial and credit markets;

•changes in general economic conditions;

•uncertainties in reserve and production estimates;

•replacing our oil and natural gas reserves;

•unanticipated recovery or production problems;

•availability, cost and adequacy of insurance coverage;

•hurricane and other weather-related interference with business operations;

•drilling and operating risks;

•production expense estimates;

•the impact of derivative positions;

•our ability to retain and motivate key executives and other necessary personnel;

•availability of drilling and production equipment and field service providers;

•the effects of delays in completion of, or shut-ins of, gas gathering systems, pipelines and processing facilities;

•potential costs associated with complying with new or modified regulations or interpretations of such regulations promulgated by the BOEM, the BSEE and the PHMSA;

•the impact of political and regulatory developments;

•risks and liabilities associated with acquired properties or businesses;

•our ability to make and integrate acquisitions;

•our substantial level of indebtedness;

•our ability to incur additional indebtedness;

•oil and gas prices and competition;

" cyber attacks; and

•our ability to generate sufficient cash flow to meet our debt service and other obligations.

Many of these factors are beyond our ability to control or predict. Any, or a combination, of these factors could materially affect our future financial condition or results of operations and the ultimate accuracy of the forward-looking statements. These forward-looking statements are not guarantees of our future performance, and our actual results and future developments may differ materially from those projected in the forward-looking statements. Management cautions against putting undue reliance on forward-looking statements or projecting any future results based on such statements.

For a further list and description of various risks, relevant factors and uncertainties that could cause future results or events to differ materially from those expressed or implied in our forward-looking statements, see “Risk Factors” in Part 1, Item 1A of this Annual Report and elsewhere in this Annual Report, our reports and registration statements filed from time to time with the SEC, and other announcements we make from time to time. Given these risks and uncertainties, you should not place undue reliance on these forward-looking statements.

Although we believe that the assumptions on which any forward-looking statements are based in this Annual Report and other periodic reports filed by us are reasonable when and as made, no assurance can be given that such assumptions will prove correct. All forward-looking statements in this Annual Report are expressly qualified in their entirety by the cautionary statements in this section and elsewhere in this Annual Report and we undertake no obligation to publicly update or revise any forward-looking statements, except as required by applicable securities laws and regulations.

Item 1A.Risk Factors

Risks Related to Our Business

Our business requires substantial capital investment and maintenance expenditures, and our capital resources may not be adequate to provide for all of our cash requirements.

Our operations are capital intensive. Our ability to replace our oil and natural gas production and maintain our production levels and reserves requires extensive capital investment, including substantial capital expenditures for the acquisition, development, production, exploration and abandonment of oil and gas properties. Our business also requires substantial expenditures for routine maintenance. Our capital requirements will depend on numerous factors, and we cannot predict accurately the timing and amount of our capital requirements. Though we have the ability to borrow under our Senior Credit Facility, we intend to finance our development and exploration capital expenditures with cash flow from operations. Because our cash flows are subject to a range of economic, competitive and business risks, we may not be able to generate sufficient cash flow from operations to meet our debt payment obligations and to fund these capital requirements. Additionally, the amounts available to us under our Senior Credit Facility may not be sufficient for our capital requirements not funded by cash flow from operations, and we may not be able to access additional financing resources for a variety of reasons, including restrictive covenants in our Senior Credit Facility and the indenture governing our senior notes. If we are unable to make scheduled payments on our Senior Credit Facility, or if our financing requirements are not met by our Senior Credit Facility and we are unable to access sources of additional financing on terms we find acceptable, our business, operations, financial condition and cash flows will be negatively impacted.

Without additional capital resources, we may be forced to limit or defer our planned oil and natural gas exploration and development program and this will adversely affect the recoverability and ultimate value of our oil and natural gas properties, in turn negatively affecting our business, financial condition and results of operations. We may also be unable to obtain sufficient credit capacity with counterparties to finance the hedging of our future crude oil and natural gas production which may limit our ability to manage price risk. As a result, we may lack the capital necessary to complete potential acquisitions, obtain credit necessary to enter into derivative contracts to hedge our future crude oil and natural gas production or to capitalize on other business opportunities.

The borrowing base under our Senior Credit Facility is subject to re-determination and could be reduced in the future if commodity prices decline, which will limit our available funding for exploration and development.

Our current borrowing base under our Senior Credit Facility is $475 million. As of February 21, 2014, we had $210 million outstanding under our Senior Credit Facility. Our borrowing base is subject to semi-annual and certain other interim re-determinations by our lenders in their sole discretion, based on the collateral value of our proved reserves. Any reduction of the borrowing base is subject to approval of lenders holding not less than 66 2/3% of the lending commitments under our Senior Credit Facility.

In the future, we may not be able to access adequate funding under our Senior Credit Facility as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base re-determination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. If oil or natural gas commodity prices deteriorate, our revised borrowing base under our Senior Credit Facility could be reduced. As a result, we may be unable to obtain adequate funding under our Senior Credit Facility. If funding is not available when needed, it could adversely affect our exploration and development plans as currently anticipated and our ability to make new acquisitions, each of which could have a material adverse effect on our production, revenues and results of operations.

In addition, if there is a decrease in our borrowing base as a result of the outcome of a subsequent borrowing base re-determination and, as a result of such decrease, the outstanding borrowings under our Senior Credit Facility exceed the re-determined borrowing base, we will be required to repay half of such difference within 45 days and the other half of such difference within 90 days. We may not have the financial resources in the future to make any mandatory principal prepayments required under our Senior Credit Facility, which would result in an event of default under the Senior Credit Facility.

Our substantial level of indebtedness could adversely affect our financial condition and prevent us from fulfilling our obligations under the notes.

We and the guarantors of the 8.25% senior notes due 2018 (the “8.25% Senior Notes”), on a consolidated basis at December 31, 2013, had outstanding $640 million of senior indebtedness, including $130 million of secured debt under our Senior Credit Facility. Our substantial level of indebtedness could have significant effects on our business. For example, our level of indebtedness and the terms of our debt agreements may:

•make it more difficult for us to satisfy our financial obligations under the 8.25% Senior Notes, our other indebtedness and our contractual and commercial commitments and increase the risk that we may default on our debt obligations;

•heighten our vulnerability to downturns in our business, our industry or in the general economy and restrict us from exploiting business opportunities or making acquisitions;

•limit management’s discretion in operating our business;

•require us to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness, thereby reducing the availability of our cash flow to fund working capital, capital expenditures, and other general corporate purposes;

•place us at a competitive disadvantage compared to our competitors that have less debt;

•limit our ability to borrow additional funds; and

•limit our flexibility in planning for, or reacting to, changes in our business, the industry in which we operate or the general economy.

Each of these factors may have a material and adverse effect on our financial condition and viability. Our ability to make payments with respect to the 8.25% Senior Notes and to satisfy our other debt obligations will depend on our future operating performance, which will be affected by prevailing economic conditions and financial, business and other factors affecting our company and industry, many of which are beyond our control. In addition, the indenture governing the 8.25% Senior Notes (the “2011 Indenture”) and our Senior Credit Facility contain financial and other restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. Our failure to comply with those covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all of our debts.

Despite our substantial level of indebtedness we may still be able to incur substantially more indebtedness, which would increase the risks associated with our leverage.

Even with our existing debt levels, we and our subsidiaries may be able to incur substantial amounts of additional debt in the future, including debt under our existing and future credit facilities. As of December 31, 2013, we had total debt outstanding of $640 million consisting of $510 million of the 8.25% Senior Notes and $130 million of outstanding borrowings under our Senior Credit Facility. In January 2014, our lenders approved a $50 million increase in our borrowing base under the facility, increasing our borrowing base to $475 million. As of February 21, 2014, we had $210.0 million outstanding and $265 million in availability under our Senior Credit Facility. Although the terms of the 8.25% Senior Notes and our current and future credit facilities will limit our ability to incur additional debt, these terms do not and will not prohibit us from incurring substantial amounts of additional debt for specific purposes or under certain circumstances. If new debt is added to our and our subsidiaries' current debt levels, the related risks that we and they now face could intensify and could further exacerbate the risks associated with our leverage.

Our Senior Credit Facility and the 2011 Indenture impose significant operating and financial restrictions on us and our subsidiaries that may prevent us from pursuing certain business opportunities and restrict our ability to operate our business.

Our Senior Credit Facility and the 2011 Indenture contain covenants that restrict our and our restricted subsidiaries' or, in the case of the Senior Credit Facility, our and all of our subsidiaries', ability to take various actions, such as:

•transferring or selling assets;

•paying dividends or distributions, buying subordinated indebtedness or securities, making certain investments or making other restricted payments;

•incurring or guaranteeing additional indebtedness or, in the case of the 2011 Indenture and only with respect to our restricted subsidiaries, issuing preferred stock;

•creating or incurring liens;

•incurring dividend or other payment restrictions affecting restricted subsidiaries;

•consummating a merger, consolidation or sale of all or substantially all our assets;

•entering into transactions with affiliates;

•engaging in business other than a business that is the same or similar to our current business or a reasonably related extension thereof;

•making capital expenditures other than those related to our business as a domestic exploration and production company;

•issuing capital stock of certain subsidiaries;

•entering into sale/leaseback transactions;

•making acquisitions or investments; and

•designating subsidiaries as unrestricted subsidiaries.

In addition, our Senior Credit Facility restricts us from entering into certain hedging contracts or extending credit. Our Senior Credit Facility also requires, and any future credit facilities may additionally require, us to comply with specified financial ratios, including regarding interest coverage, total leverage, current assets to current liabilities or other similar ratios.

We may also be prevented from taking advantage of business opportunities that arise if we fail to meet certain ratios or because of the limitations imposed on us by the restrictive covenants under these agreements. The restrictions contained in our Senior Credit Facility and the 2011 Indenture may also limit our ability to plan for or react to market conditions, meet capital needs or otherwise restrict our activities or business plans and adversely affect our ability to finance our operations, enter into acquisitions, execute our business strategy, effectively compete with companies that are not similarly restricted or engage in other business activities that would be in our interest. In the future, we may also incur debt obligations that might subject us to additional and different restrictive covenants that could affect our financial and operational flexibility. We cannot assure you that we will be granted waivers or amendments to these agreements if for any reason we are unable to comply with these agreements, or that we will be able to refinance our debt on acceptable terms or at all should we seek to do so.

Our ability to comply with these covenants will likely be affected by events beyond our control, and we cannot assure you that we will satisfy those requirements. A breach of any of these provisions could result in a default under our Senior Credit Facility, the 2011 Indenture or any future credit facilities we may enter into, which could allow all amounts outstanding thereunder to be declared immediately due and payable, subject to the terms and conditions of the documents governing such indebtedness. If we were unable to repay the accelerated amounts, our secured lenders could proceed against the collateral granted to them to secure such indebtedness. This would likely in turn trigger cross-acceleration and cross-default rights under any other credit facilities and indentures, if any then exist governing the notes and the terms of our other indebtedness outstanding at such time. If the amounts outstanding under our Senior Credit Facility, the 8.25% Senior Notes or any other indebtedness outstanding at such time were to be accelerated or were the subject of foreclosure actions, we cannot assure you that our assets would be sufficient to repay in full the money owed to the lenders or to our other debt holders.

A substantial or extended decline in oil and natural gas prices may have a material adverse effect on our business, financial condition, results of operations, cash flows and our ability to meet our debt obligations, operating cost requirements, capital expenditure requirements and other financial commitments.

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, financial condition, cash flow, access to capital and future rate of growth. Oil and natural gas are commodities and, as a result, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. While oil prices have recovered from their low levels in 2009, there are different views about the strength of the economic recovery and future demand for oil and natural gas. Consequently, there is no assurance that oil prices will not fall again. Domestic natural gas prices have recently experienced ten year lows and may remain at these low levels relative to historical prices for an extended period of time. The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include:

•changes in the global supply, demand and inventories of oil;

•domestic natural gas supply, demand and inventories;

•the actions of the Organization of Petroleum Exporting Countries;

•the price and quantity of foreign imports of oil;

•the price and availability of liquefied natural gas imports;

•political conditions, including embargoes, in or affecting other oil-producing countries;

•economic and energy infrastructure disruptions caused by actual or threatened acts of war, or terrorist activities, or national security measures deployed to protect the United States from such actual or threatened acts or activities;

•economic stability of major oil and natural gas companies and the interdependence of oil and natural gas and energy trading companies;

•the level of worldwide oil and natural gas exploration and production activity;

•weather conditions, including energy infrastructure disruptions resulting from those conditions;

•technological advances affecting energy consumption; and

•the price and availability of alternative fuels.

Oil prices as of the date of this Annual Report permit us to maintain the minimal investment necessary to mitigate the impact of natural reservoir declines on our current production levels. However, if oil prices fall to their previous low levels, we may not be able to replace our reserves and our production may decline significantly. As a result, we could experience a decline in our revenues and available capital, which would likely substantially decrease our capital expenditures, drilling activities and operations.

Our current operations and a significant part of the value of our production and reserves are concentrated in the Gulf of Mexico. Because of this concentration, any production problems, impacts of adverse weather conditions or inaccuracies in reserve estimates related to these areas could have a material adverse effect on our business.

Virtually all of our current operations are concentrated in the Gulf of Mexico region. We are more vulnerable to operational, regulatory and other risks associated with the Gulf of Mexico, including the risk of adverse weather conditions, than many of our competitors that are more geographically diversified because all or a substantial portion of our operations could experience the same condition at the same time.

At December 31, 2013, the Ship Shoal 208, East Bay and West Delta fields contained approximately 24%, 17%, and 15%, respectively, of our estimated proved reserves. If the actual reserves associated with these properties are less than our estimated reserves, such a reduction of reserves could have a material adverse effect on our business, financial condition, results of operations and cash flows.

During the 2008 hurricane season, our production was reduced by approximately 21%, on an annual basis, as a result of damage to third party pipelines caused by two hurricanes. The hurricane damage limited our ability to sell our production from certain properties for extended periods of time during the third and fourth quarters of 2008. If mechanical problems, storms or other events were to curtail a substantial portion of the production in these areas, such a curtailment could have a material adverse effect on our business, financial condition, results of operations and cash flows.

The relatively steep decline curves generally associated with oil and gas properties located in the Gulf of Mexico region subjects us to higher reserve replacement needs.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. High initial production rates generally result in recovery of a relatively higher percentage of reserves from properties during the initial few years of production, often followed by a rapid decline in the rate of production.

Because substantially all of our operations are concentrated in the Gulf of Mexico, and because production from reservoirs in the Gulf of Mexico region generally declines more rapidly compared to reservoirs in many other producing regions of the world, our reserve replacement needs are relatively greater than those of producers with reserves outside the Gulf of Mexico region.

As of December 31, 2013, our independent petroleum engineers estimate that, on average, 60% of our total proved reserves will be produced within five years. We will have to continue to develop, exploit, find or acquire additional reserves to sustain our current production levels and to grow our production.

The cost of operating our business, including our estimates of future asset retirement obligations, may vary significantly especially because our operations are concentrated in the Gulf of Mexico.

We are responsible for plugging and abandoning wellbores and decommissioning associated platforms, pipelines and facilities on our oil and natural gas properties. Estimating future abandonment and decommissioning costs in the Gulf of Mexico is difficult because most of the removal obligations may be many years in the future, regulatory requirements are subject to change or more restrictive interpretation, and technologies are constantly evolving, which may result in increased costs. As a result, we may make significant increases or decreases to our estimated asset retirement obligations (“ARO”) in future periods. Some of our offshore operations are conducted on federal leases that are administered by the BOEM and are required to comply with the regulations and orders promulgated by the BOEM and BSEE under OCSLA. We are subject to regulations over the decommissioning of wells and platforms. The regulations impose stringent requirements for decommissioning facilities that pose a hazard to safety or the environment, as well as for facilities that are not useful for lease operations and that are not capable of oil and natural gas production in “paying quantities.” The regulations also impose deadlines for removing platforms or other facilities that are no longer useful for operations, and deadlines for plugging, abandoning or performing downhole zonal isolation on wells that are no longer useful for operations and that are no longer capable of production in paying quantities.

Because we operate in the Gulf of Mexico, platforms, facilities and equipment are subject to damage or destruction as a result of hurricanes. The estimated cost to plug and abandon a well or dismantle a platform can change materially if the platform from which the work was anticipated to be performed is damaged or toppled. Accordingly, our estimates of future abandonment and decommissioning costs could differ materially from what we may ultimately incur. The effects of Hurricanes Katrina and Rita during the 2005 hurricane season and Hurricanes Ike and Gustav in 2008 significantly impacted oil and gas operations on the OCS. The effects included structural damage to fixed production facilities, semi-submersibles and jack-up drilling rigs which could create the potential for catastrophic damage to key infrastructure and the resultant pollution. The former BOEMRE has issued still active guidance through NTLs, aimed at improving platform survivability by taking into account environmental and oceanic conditions in the design of platforms and related structures.

In September 2013, after receiving further interpretations of the BSEE regulations, the estimated scope of required work increased and our estimates of future abandonment and decommissioning costs increased. It is possible that similar, if not more stringent, design and operational requirements will be issued by the BOEM or BSEE in the future and these new requirements could further increase our operating costs. The BOEM, BSEE and other regulatory bodies, including those regulating the decommissioning of our pipelines and facilities under the jurisdiction of the state of Louisiana, may change their requirements or enforce requirements in a manner inconsistent with our expectations, which could materially increase the cost of such activities and/or accelerate the timing of cash expenditures and could have a material adverse effect on our financial position, results of operations and cash flows.

We may not be able to keep pace with technological developments in our industry.

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or competitive pressures may force us to implement those new technologies at substantial costs. In addition, other natural gas and oil companies may have greater financial, technical, and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures, including the inability to adapt technological advancements to a Gulf of Mexico setting, or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition, and results of operations could be materially adversely affected.

With respect to a portion of our properties, we are not the operator and therefore are not in a position to control the timing of development efforts, the associated costs, or the rate of production of the reserves on such properties.

As we carry out our planned drilling program, we will not serve as operator of all planned wells. As of December 31, 2013, we operated approximately 89% of our properties, based on proved reserves at December 31, 2013. As a result, we may have limited ability to exercise influence over the operations of some non-operated properties or their associated costs. Dependence on the operator and other working interest owners for these projects, and limited ability to influence operations and associated costs could prevent the realization of targeted returns on capital in drilling or acquisition activities. The success and timing of development and exploitation activities on properties operated by others depend upon a number of factors that will be largely outside of our control, including:

•the timing and amount of capital expenditures;

•the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel;

•the operator’s expertise and financial resources;

•approval of other participants in drilling wells;

•selection of technology; and

•the rate of production of the reserves.

Our operations in the deepwater Gulf of Mexico area present unique operating risks.

The deepwater Gulf of Mexico area has had relatively limited drilling activity due to risks associated with geological complexity, water depth and higher drilling and development costs, which could result in substantial cost overruns and/or uneconomic projects or wells. Because we have operations in the deepwater Gulf of Mexico area, we are exposed to these risks.

If we place hedges on future production and encounter difficulties meeting that production, we may not realize the originally anticipated cash flows.

Our assets consist of a mix of reserves, with some being developed while others are undeveloped. To the extent that we sell the production of these reserves on a forward-looking basis but do not realize that anticipated level of production, our cash flow may be adversely affected if energy prices rise above the prices for the forward-looking sales. In this case, we would be required to make payments to the purchaser of the forward-looking sale equal to the difference between the current commodity price and that in the sales contract multiplied by the physical volume of the shortfall. There is the risk that production estimates could be inaccurate or that storms or other unanticipated problems could cause the production to be less than the amount anticipated, causing us to make payments to the purchasers pursuant to the terms of the hedging contracts.

Our price risk management activities could result in financial losses or could reduce our income, which may adversely affect our cash flows.

We enter into derivative contracts to reduce the impact of oil and natural gas price volatility on our cash flow from operations. Currently, we use crude oil and natural gas swap arrangements to mitigate the volatility of future oil prices received.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative contracts for such period. If the actual amount of production is higher than we estimate, we will have greater commodity price exposure than we intended as our excess production will be unhedged. If the actual amount of production is lower than the notional amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions at the current market rates without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, our price risk management activities are subject to the following risks:

•a counterparty may not perform its obligation under the applicable derivative instrument;

•there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and

•the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures.

Loss of key management and failure to attract qualified management could negatively impact our operations.

Successfully implementing our strategies will depend, in part, on our management team. The loss of members of our management team could have an adverse effect on our business. Our business will also be dependent upon our ability to attract and retain qualified personnel. Acquiring and keeping qualified personnel could prove more difficult or cost substantially more than estimated. This could cause us to incur greater costs, or prevent us from pursuing our strategy as quickly as we would otherwise wish to do.

Our ability to collect payments from our partners depends on the partners' creditworthiness.

In operating our oil and natural gas properties, we typically incur costs on behalf of our partners in advance of billing and collecting our partners' share of those costs. Some of our partners are highly leveraged and may become unable to pay us for their share of the operating costs. Further, a significant adverse change in the financial and/or credit position of a partner could require us to assume greater credit risk relating to that partner and could limit our ability to collect joint interest receivables. Failure to receive payments from our partners for their share of costs incurred on our oil and natural gas properties could adversely affect our results of operations, financial condition and cash flows.

Provisions in our organizational documents and under Delaware law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock.

The existence of some provisions in our organizational documents and under Delaware law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock. The provisions in our Certificate of Incorporation and Bylaws that could delay or prevent an unsolicited change in control of our company include:

•the board of directors' ability to issue shares of preferred stock and determine the terms of the preferred stock without approval of common stockholders; and

•a prohibition on the right of stockholders to call meetings and limitations on the right of stockholders to present proposals or make nominations at stockholder meetings.

In addition, Delaware law imposes some restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock.

Risks Related to Our Acquisition Strategy

Our acquisition strategy involves potential risks that could adversely impact our future financial performance.

A significant component of our business strategy is to acquire oil and gas properties. Acquisitions of producing properties from third parties require us to assess many factors that are inherently inexact and may be inaccurate, including:

•the risk that reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;

•the risk that financial information relating to the acquired assets may not be accurate;

•inaccurate assumptions about revenues and costs, including synergies;

•significant increases in our indebtedness and working capital requirements;

•an inability to transition and integrate successfully or timely the businesses we acquire;

•the cost of transition and integration of data systems and processes;

•potential environmental problems and costs;

•the assumption of unknown liabilities;

•limitations on rights to indemnity from the seller;

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

•increased demands on existing personnel and on our corporate structure;

•increased responsibility for plugging and abandonment costs;

•customer or key employee losses of the acquired businesses; and

•the failure to realize expected growth or profitability.

The scope and cost of these risks may ultimately be materially greater than estimated at the time of the acquisition. Further, our future acquisition costs may be higher than those we have achieved historically. Any of these factors could adversely impact our future financial performance, results of operations and cash flows. Future transactions may prove to stretch our internal resources and infrastructure. As a result, we may need to hire additional personnel and invest in additional resources, which will increase our costs. Any further acquisitions we make over the short term would likely exacerbate these risks.

We may record material impairments to the carrying values of our oil and natural gas properties if oil and gas prices decline from prices we used to estimate the acquisition fair values of acquired oil and gas properties.

We record acquisitions of oil and natural gas properties using the purchase method of accounting which requires that we record the acquired oil and natural gas properties at their fair values as of the acquisition date. We may be required to recognize material non-cash impairment charges in future reporting periods if market prices for oil or natural gas decline and, as a result, the estimated fair values of the acquired oil and natural gas properties decline from the values estimated as of the acquisition date.

We may be unable to successfully integrate the operations of the properties we acquire.

Integration of the operations of the properties we acquire with our existing business will be a complex, time-consuming and costly process. Failure to successfully integrate the acquired businesses and operations in a timely manner may have a material adverse effect on our business, financial condition, results of operations and cash flows. The difficulties of combining the acquired operations include, among other things:

•operating a significantly larger combined organization;

•integrating corporate, technological and administrative functions;

•integrating internal controls and other corporate governance matters;

•diverting management’s attention from other business concerns;

•loss of key vendors from the acquired businesses;

•a significant increase in our indebtedness; and

•potential environmental or regulatory liabilities and title problems.

The process of integrating our operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer. Our operating performance, revenues and costs could be materially adversely affected if:

•we are not successful in completing the integration of acquired properties into our operations;

•the integration takes longer or is more complex than anticipated; or

•we cannot operate acquired properties as effectively as we anticipate.

We may not have fully identified liabilities associated with properties or assets we acquire or obtained adequate protection from sellers against liabilities.

Our assessments of potential acquisitions may not reveal all existing or potential problems with the subject properties or permit us to become adequately familiar with the properties in order to evaluate fully their deficiencies and capabilities. In the course of our due diligence, we may not inspect every well, platform or pipeline. Our inspections may not identify structural and environmental problems, such as pipeline corrosion or groundwater contamination. We may not obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations. As a result, we may not realize all of the anticipated benefits from future acquisitions, such as increased earnings, cost savings and revenue enhancements.

The properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the acquired properties or obtain protection from sellers against such liabilities.

The properties we acquire may not produce as expected, may be in an unexpected condition and we may be subject to increased costs and liabilities, including environmental liabilities. Although we review properties prior to acquisition in a manner consistent with industry practices, such reviews are not capable of identifying all potential adverse conditions. Furthermore, we may not be able to subject the preparation of reserve estimates for acquired properties to the same internal controls we have for the preparation of reserve estimates for our existing properties. Generally, it is not feasible to review in depth every individual property involved in each acquisition. We focus our review efforts on the higher-value properties or properties with known adverse conditions and will sample the remainder. However, even a detailed review of records and properties and preparation of reserve reports in accordance with our internal controls may not necessarily reveal existing or potential problems or permit us to become sufficiently familiar with the properties to fully assess their condition, any deficiencies, and development potential.

If we are unable to execute our acquisition strategy successfully, our business may not continue to grow.

We intend to pursue opportunistic acquisitions that leverage our organizational strengths. However, we may not be able to identify and consummate future acquisitions successfully, and assets that we do acquire may not yield anticipated benefits. Our failure to execute our acquisition strategy successfully in the future could limit our ability to continue to grow our business.

Risks Related to Our Industry

Reserve estimates depend 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 estimated values of our reserves.

The process of estimating oil and natural gas reserves is complex, requiring interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves disclosed in this Annual Report.

Estimates of oil and natural gas reserves are inherently imprecise. The preparation of our reserve estimates requires projections of production rates and timing of development expenditures, analysis of available geological, geophysical, production and engineering data, and assumptions about oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The extent, quality and reliability of this data can vary. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, drilling and operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates. If our estimates of the recoverable reserve volumes on a property are revised downward, if development costs exceed previous estimates or if commodity prices decrease, as discussed elsewhere in these risk factors, we may be required to record an impairment to our property and equipment, which could have a material adverse effect on our financial position and results of operations. Once recorded, an impairment of property and equipment may not be reversed at a later date. Our ability to obtain financing in the future may depend in part on our estimate of the proved oil and natural gas reserves for properties that will serve as collateral. If proved reserves on a property are revised downward, our ability to acquire adequate funding may be significantly reduced.

The present value of future net cash flows from our proved 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 proved reserves and the standardized measure of discounted future net cash flows referred to in this Annual Report should not be assumed to represent or approximate the current market value of our estimated proved oil and natural gas reserves.

In accordance with SEC requirements, the estimated discounted future net cash flows from our proved reserves are computed using prices based on the unweighted, arithmetic average of the closing price on the first day of each of the twelve months during the preceding fiscal year and costs as of the date of the estimate held constant for the life of the reserves. However, actual future net cash flows from our natural gas and oil properties will be affected by factors such as:

•the volume, pricing and duration of our natural gas and oil hedging contracts;

•supply of and demand for natural gas and oil;

•actual prices we receive for natural gas and oil;

•our actual operating costs in producing natural gas and oil;

•the amount and timing of our capital expenditures and decommissioning costs;

•the amount and timing of actual production; 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 proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows 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. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

Our estimates of proved reserves and related PV-10 and standardized measure of discounted future net cash flows have been prepared in accordance with new SEC rules, which went into effect for fiscal years ending on or after December 31, 2009, and may make comparisons to prior periods difficult and could limit our ability to book additional proved undeveloped reserves in the future.

This Annual Report presents estimates of our proved reserves, related PV-10 and standardized measure of discounted future net cash flows as of December 31, 2013, 2012 and 2011, all of which have been prepared and presented under new SEC rules. These new rules were effective for fiscal years ending on or after December 31, 2009, and require companies to prepare their reserves estimates using revised reserve definitions and revised pricing based on 12-month unweighted first-day-of the-month average pricing. The previous rules required that reserve estimates be calculated using year-end pricing. As a result of these changes, and because the new rules do not have a retroactive effect to periods that ended prior to December 31, 2009, direct comparisons to our prior period reserves amounts may be more difficult.

Another impact of the new SEC rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This new rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our future proved undeveloped reserves if we do not drill and develop those reserves within the required five-year timeframe.

The SEC has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules and may not issue further interpretive guidance on the new rules. Accordingly, the estimates of our proved reserves included in this Annual Report could differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

We may be limited in our ability to book additional proved undeveloped reserves under recent SEC rules.

We have included in this Annual Report certain estimates of our proved reserves as of December 31, 2013 prepared in a manner consistent with our and our independent petroleum engineer’s interpretation of the recent SEC rules relating to modernizing reserve estimation and disclosure requirements for oil and natural gas companies. These recent rules were effective for annual reporting periods ended on or after December 31, 2009. Included within these recent SEC reserve rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years of the date of booking. This rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Further, if we postpone drilling of proved undeveloped reserves beyond this five-year development horizon, we may be required to write-off reserves previously recognized as proved undeveloped. As of December 31, 2013, approximately 29% of our total proved reserves were undeveloped, and approximately 29% of our total proved reserves were developed non-producing reserves. There can be no assurance that all of those reserves will ultimately be developed or produced.

If we are unable to replace the reserves that we have produced, our reserves and future revenues will decline.

Our future success depends on our ability to find, develop, acquire and produce oil and natural gas reserves that are economically recoverable. Lower commodity prices and increased costs associated with exploration, development and production may lower the threshold of economic recoverability. Though our 2014 fiscal year capital budget contemplates the deployment of a larger amount of capital compared to the capital expenditures in 2013, there can be no assurance that we will be able to grow production through the drill-bit at rates we have experienced in the past. Though we intend to pursue development and acquisition opportunities, there is no assurance that our efforts will yield their intended results. Without continued successful acquisition or exploration activities, our reserves and revenues will decline as a result of our current reserves being depleted by production. We may not be able to find or acquire additional reserves on an economic basis.

Unanticipated decommissioning costs could materially adversely affect our future financial position and results of operations.

We may become responsible for unanticipated costs associated with abandoning and reclaiming wells, facilities and pipelines. Abandonment and reclamation of facilities and the costs associated therewith are often referred to as "decommissioning." Should decommissioning be required that is not presently anticipated, or should the decommissioning be accelerated (such as can happen after a hurricane), these costs may exceed the value of reserves remaining at any particular time. We may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy these decommissioning costs could have a material adverse effect on our financial position and results of operations.

We may not be insured against all of the operating risks to which our business is exposed.

In accordance with industry practice, we maintain insurance coverage against some, but not all, of the operating risks to which our business is exposed. We insure some, but not all, of our properties from operational and hurricane related events. We currently have insurance policies that include coverage for general liability, physical damage to our oil and gas properties, operational control of well, oil pollution, third party liability, workers' compensation and employers' liability and other coverage. Our insurance coverage includes deductibles that must be met prior to recovery, as well as sub-limits.

Additionally, our insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages and losses.

Currently, we have general liability insurance coverage with an annual aggregate limit of $2.0 million and umbrella excess liabilities coverage with an aggregate limit of $200.0 million applicable to our working interests. Our general liability policy is subject to a $25,000 per incident deductible. We also have an offshore property physical damage and operators extra expense policies that contain an aggregate of $201.4 million of named windstorm limit of which we self-insure approximately 9%. Recoveries from these policies are subject to a $2.5 million deductible that applies to non-named windstorm occurrences and a $27.5 million deductible that applies to named windstorm events except for East Bay central facilities and rental compressor losses, which are subject to a 1.5% deductible of the scheduled values of the items making up a loss, but always subject to a $25,000 minimum. Further, there are sub-limits within the named windstorm annual aggregate limit for re-drill, non-blowout plugging and abandonment and excess removal of wreck. Our operational control of well coverage provides limits that vary by well location and depth and range from a combined single limit of $20 million to $75 million per occurrence. Deepwater wells have a coverage limit of $50 million per occurrence. Additionally, we maintain $150 million in oil pollution liability coverage as required under the Oil Pollution Act of 1990. Our control of well and oil pollution liability policy limits are scaled proportionately to our working interests, except for our deepwater control of well coverage, to which the $50 million limit applies to our working interest. Under our service agreements, including drilling contracts, generally we are indemnified for injuries and death of the service provider’s employees as well as contractors and subcontractors hired by the service provider.

An operational or hurricane related event may cause damage or liability in excess of our coverage, which might materially adversely impact our financial position. We may be liable for damages from an event relating to a project in which we are a non-operator, but have a working interest in such project. Such an event may also cause a significant interruption to our business, which might also materially adversely impact our financial position. For example, we experienced production interruptions in 2005, 2006 and 2007 from Hurricanes Katrina and Rita, in 2008 and 2009 from Hurricanes Gustav and Ike for which we had no production interruption insurance.

We regularly reevaluate the purchase of insurance, policy limits and terms. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to maintain minimal or no insurance coverage. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations in the Gulf of Mexico, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of operations.

We maintain an Oil Spill Response Plan (the “Plan”) that defines our response requirements and procedures and remediation plans in the event we have an oil spill. Oil Spill Response Plans will generally be approved by the BSEE bi-annually, except when changes are required, in which case revised plans are required to be submitted for approval at the time changes are made. We believe the Plan specifications are consistent with the requirements set forth by the BSEE.

The Company has contracted with an emergency and spill response management consultant, which would provide management expertise, personnel and equipment, under the supervision of the Company, in the event of an incident requiring a coordinated response. Additionally, the Company is a member of Clean Gulf Associates (“CGA”), a not-for-profit association of producing and pipeline companies operating in the Gulf of Mexico and has capabilities to simultaneously respond to multiple spills. CGA is structured to provide an effective method of staging response equipment and providing spill response for its member companies in the Gulf of Mexico. On January 1, 2013, CGA entered into an agreement with Clean Gulf Associates Services, LLC (“CGAS”), an affiliate of T&T Marine Salvage Inc. (“TTMS”). Through this agreement, CGAS will store, maintain, deploy and operate all CGA-owned equipment and provide response personnel. This agreement replaced the expiring Equipment Management, Contractor Services and Bareboat Charter Agreement that CGA had previously entered into with Marine Spill Response Corporation. CGAS maintains CGA's equipment in various warehouse locations (currently including 50 skimmers with various estimated daily recovery capacities, numerous containment and storage systems including thousands of feet of boom and one fire boom system, tanks and storage barges, wildlife cleaning and rehabilitation facilities, and both aerial and vessel dispersant spray systems) at staging points around the Gulf of Mexico in its ready state. In the event of a spill, CGAS mobilizes appropriate equipment to CGA members. In addition, CGA maintains a contract with Airborne Support Inc., which provides aircraft and dispersant capabilities for CGA member companies.

Additional resources are available to the Company on an as-needed basis other than as a member of CGA, such as those of CGAS. CGAS has oil spill response equipment independent of, and in addition to, CGA's equipment. CGAS's equipment currently includes, according to CGAS's website, skimmer, containment boom, pumps and lightering equipment, vacuum units and sorbents. In the event of a spill, CGAS activates contractors as necessary to provide additional resources or support services requested by its customers.

The response effectiveness, equipment and resources of these companies may change from time-to-time and current information is generally available on the websites of each of these organizations. There can be no assurances that the Company, together with the organizations described above will be able to effectively manage all emergency and/or spill response activities that may arise and any failures to do so may materially adversely impact the Company's financial position, results of operations and cash flows.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations.

Losses and liabilities arising from uninsured and underinsured events could materially adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

•environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;

•abnormally pressured formations;

•blow-outs and surface cratering;

•mechanical difficulties and pipe, cement, sub-sea well or pipeline failures;

•fires and explosions;

•personal injuries and death; and

•natural disasters, especially hurricanes and tropical storms in the Gulf of Mexico region.

If we experience any of these problems, well bores, platforms, gathering systems and processing facilities could be affected, which could adversely affect our ability to conduct operations. We could also incur substantial losses because of costs and/or liability incurred as a result of:

•injury or loss of life;

•severe damage to and destruction of property, natural resources and equipment;

•pollution and other environmental damage;

•clean-up responsibilities;

•regulatory investigations and penalties;

•suspension of our operations; and

•repairs to resume operations.

Exploring for and producing oil and natural gas are high-risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future success will depend on the success of our exploration and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in planned expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling activity, including the following:

- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions, such as hurricanes and tropical storms;
- reductions in oil and natural gas prices;
- title problems;
- limitations in the market for oil and natural gas; and
- cost of services to drill wells.

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If we are unable to effectively manage the commodity price risk of our production if energy prices fall, we may not realize the anticipated cash flows from our acquisitions.

Compared to some other participants in the oil and gas industry, we are a relatively small company with modest resources. Therefore, there is the possibility that we may be unable to find counterparties willing to enter into derivative arrangements with us or, to the extent counterparties are willing to enter into derivative arrangements with us, we may be required to either purchase relatively expensive put options, or commit to deliver future production, in order to manage the commodity price risk of our future production. To the extent that we commit to deliver future production, we may be forced to post cash collateral to counterparties as they mark to market these financial hedges. This funding requirement may limit the level of commodity price risk management that we are prudently able to complete. In addition, we are unlikely to hedge undeveloped reserves to the same extent that we hedge the anticipated production from proved developed reserves. If we fail to manage the commodity price risk of our production and energy prices fall, we may not be able to realize the cash flows from our assets that are currently anticipated even if we are successful in increasing the production and ultimate recovery of reserves.

Periods of high cost or lack of availability of drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute on a timely basis our exploration and development plans.

Substantially all of our current operations are concentrated in the Gulf of Mexico region. Shortages and the high cost of drilling rigs, equipment, supplies or personnel that occur in this region from time to time could delay or adversely affect our exploration and development plans, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. Periodically, as a result of increased drilling activity or a decrease in the supply of equipment, materials and services, we have experienced increases in associated costs, including those related to drilling rigs, equipment, supplies and personnel and the services and products of other vendors to the industry. Increased drilling activity in the Gulf of Mexico and in other offshore areas around the world also decreases the availability of offshore rigs in the Gulf of Mexico. As a result, costs may increase in the future and necessary equipment and services may not be available on terms acceptable to us. Redeployment of drilling rigs to areas other than the Gulf of Mexico in the wake of the Deepwater Horizon incident in April 2010, discussed below, may reduce the availability of offshore rigs, which could increase costs in future years.

Impediments to transporting our products may limit our access to oil and natural gas markets or delay our production.

Our ability to market our oil and natural gas production depends on a number of factors, including the proximity of our reserves to pipelines and terminal facilities, the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties and the availability of satisfactory oil and natural gas transportation arrangements. In deepwater operations, market access depends on the proximity of, and our ability to tie into, existing production platforms owned or operated by third parties and the ability to negotiate commercially satisfactory arrangements with the owners or operators. These facilities and systems may be shut-in due to factors outside of our control. If any of these third party services and arrangements become partially or fully unavailable, or if we are unable to secure such services and arrangements on acceptable terms, or if the gas quality specification for their pipelines or facilities changes so as to restrict our ability to transport gas on these pipelines or facilities, our production could be limited or delayed and our revenues could be adversely affected.

Competition in the oil and natural gas industry is intense, which may adversely affect us.

We operate in a highly competitive environment for acquiring oil and natural gas properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in Gulf of Mexico activities. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects 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. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. There can be no assurance that we will be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital. If we are unable to compete successfully in these areas in the future, our revenues and growth may be diminished or restricted.

The explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico in April 2010 and the resulting oil spill may significantly increase our risks, costs and delays.

The explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico in April 2010 and the resulting oil spill may significantly impact the risks we face. The Deepwater Horizon incident and resulting legislative, regulatory and enforcement changes, including increased tort liability, could increase our liability if any incidents occur on our offshore operations. We cannot predict the ultimate impact the Deepwater Horizon incident and resulting changes in regulation of offshore oil and natural gas operations will have on us.

In response to the spill, and during a moratorium on deepwater (below 500 feet) drilling activities implemented between May 30, 2010 and October 12, 2010, the former BOEMRE issued a series of active NTLs and adopted changes to its regulations to impose a variety of new measures intended to help prevent a similar disaster in the future.

Offshore operators, including those operating in deepwater, OCS waters and shallow waters, where we have substantial operations, must comply with strict new safety and operating requirements. For example, permit applications for drilling projects must meet new standards with respect to well design, casing and cementing, blowout preventers, safety certification, emergency response, and worker training. Operators of all offshore waters are also required to demonstrate the availability of adequate spill response and blowout containment resources. In addition, the BSEE imposed, for the first time, requirements that offshore operators maintain comprehensive safety and environmental programs. Such developments have the potential to increase our costs of doing business. Notwithstanding the lifting of the moratorium on October 12, 2010, there have been significant delays in permitting and an overall decline in the number of permits that have been issued. We anticipate that there will continue to be delays in permitting as these and possible additional regulatory initiatives are fully implemented.

Legislative and regulatory initiatives relating to offshore operations, which include consideration of increases in the minimum levels of demonstrated financial responsibility required to conduct exploration and production operations on the outer continental shelf and elimination of liability limitations on damages, will, if adopted, likely result in increased costs and additional operating restrictions and could have a material adverse effect on our business.

In addition to new regulatory requirements, there have been a variety of proposals to change existing laws and regulations that could materially adversely affect our operations and cause us to incur substantial costs, including by raising operating costs, increasing insurance premiums, delaying drilling operations and increasing regulatory burdens. We are not able to predict the likelihood of such proposals actually becoming law or the nature, extent or timing of any interim or final rules that may result from such proposals. If enacted, such changes could lead to a wide variety of other unforeseeable consequences that make operations in the Gulf of Mexico and other offshore waters more difficult, more time consuming, and more costly. For example, there have been proposals in the U.S. Congress to amend OPA, including by eliminating limits on liability and further increasing applicable financial assurance requirements, in response to the Deepwater Horizon incident. If OPA were amended to materially increase the minimum level of financial responsibility beyond current requirements, we may experience difficulty in providing financial assurances sufficient to comply with this requirement. If we are unable to provide the level of financial assurance required by OPA, we may be forced to sell our properties or operations located in offshore waters or enter into partnerships with other companies that can meet the increased financial responsibility requirement, and any such developments could have an adverse effect on the value of our offshore assets and the results of our operations. We cannot predict at this time whether or when any such changes in current laws and regulations will occur.

Recent hurricanes in the Gulf of Mexico, including Ivan, Katrina, Rita, Gustav and Ike, caused damage to a number of unaffiliated drilling rigs. BOEM and BSEE issued guidelines imposing new requirements relating to tie-downs on drilling rigs and other permanent equipment attached to outer continental shelf production platforms to increase the likelihood of survival of such rigs during hurricane events. The guidelines also impose new data collection and disclosure requirements. Such hurricane protection measures, and any new or more stringent guidelines or formal rules, may subject our operations to increased costs or limit operational capabilities during storm events.

The recent reorganization of the former BOEMRE may impact potential future regulations or enforcement that may affect our operations.

On October 1, 2011, the U.S. Department of the Interior completed its reorganization of the BOEMRE (formerly the Minerals Management Service) by dividing its offshore oil and gas responsibilities among three independent agencies. The first phase of reorganization took place in 2010 when the revenue collection arm of the former Minerals Management Service became the Office of Natural Resources Revenue. A year later the BOEMRE was replaced with the BOEM, which has responsibility for leasing and environmental studies, and the BSEE, which has responsibility for field operations, including inspections, regulatory compliance, and oil spill response. At this time, we cannot predict the impact that this reorganization, or future regulations or enforcement actions taken by the new agencies, may have on our operations.

We may need to obtain bonds or other surety in order to maintain compliance with applicable regulations, which, if required, could be costly and reduce borrowings available under our Senior Credit Facility or any other credit facilities we may enter into in the future.

Regulations with respect to offshore operations govern, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the OCS of the Gulf of Mexico and removal of facilities. Lessees subject to these regulations are generally required to have substantial net worth or post bonds or other acceptable assurances so that the various obligations of lessees on the Gulf of Mexico shelf will be met. While we believe that we are currently exempt from such supplemental bonding requirements, the BOEM or BSEE could re-evaluate or increase our obligations, which could cause us to lose our exemption. The cost of these bonds or other surety could be substantial and there is no assurance that bonds or other surety could be obtained in all cases. In addition, we may be required to provide letters of credit to support the issuance of these bonds or other surety. Such letters of credit would likely be issued under our Senior Credit Facility or another credit facility we may enter into in the future and would reduce the amount of borrowings available under such facility in the amount of any such letter of credit obligations. The cost of compliance with these supplemental bonding requirements could materially and adversely affect our financial condition, cash flows and results of operations.

We are subject to extensive governmental laws and regulations, including environmental regulations and permit requirements that can adversely affect the cost, manner or feasibility of doing business and could result in restrictions on our operations or civil or criminal liability.

Our exploration, development and production operations, our activities in connection with storage and transportation of oil and other hydrocarbons and our use of facilities for treating, processing or otherwise handling hydrocarbons and related wastes are subject to various federal, state and local laws, orders and regulations. Such laws regulate, among other things, air emissions, water and stormwater discharges, releases of oil and hazardous substances and the development, implementation, inspection and maintenance of emergency response procedures. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties or the imposition of injunctive relief, including possible suspension of our operations. Certain environmental laws impose strict liability for remediation of spills and releases of oil and hazardous substances, as well as for any resulting damage to natural resources, and can include claims by private parties as well as governmental agencies.

The construction and operation of our projects also require numerous permits and approvals from governmental agencies. If we are unable to acquire or renew permits and approvals required for operations, we may be forced to suspend or cease operations altogether. We may not be able to obtain all necessary permits and approvals, and as a result our operations may be adversely affected. In addition, obtaining all necessary permits and approvals may necessitate substantial expenditures and may create a risk of expensive delays or loss of value if a project is unable to proceed as planned due to changing requirements or local opposition.

In addition, we are required to satisfy insurance and financial responsibility requirements for potential oil spills and other pollution incidents. While our current insurance for such events is consistent with the requirements of OPA, there is no assurance that such coverage will continue to be available in the future or that we will be able to obtain such insurance. Even if insurance is available and we have obtained coverage, the insurance coverage may not be adequate to satisfy all resulting liabilities should a significant claim occur. Any of these scenarios could have a material adverse effect on our business, operating results and financial condition.

We are exposed to claims under environmental requirements and such claims have been made against us. In the United States, environmental requirements and regulations typically impose strict liability. Strict liability means that in some situations we could be exposed to liability for cleanup costs, natural resource damages, and other damages as a result of our conduct that was lawful at the time it occurred or the conduct of prior operators or other third parties. Liability for damages arising as a result of future claims brought under environmental laws could be substantial and could have a material adverse effect on our financial position, results of operations, and cash flows, or any of them. These potential liabilities may arise from both our historical operations and the historical operations of companies or properties that we have acquired. We also could be subject to third-party claims with respect to environmental matters for which we have been named as a potentially responsible party.

Future compliance with laws and regulations, including environmental, production, transportation, sales, rate and tax rules and regulations, and any changes to such laws or regulations, may reduce our profitability and have a material adverse effect on our financial position, liquidity and cash flows. Such laws and regulations may require more stringent and costly waste handling, storage, transport, disposal or cleanup requirements. See “Business—Environmental Matters.”

The adoption of climate change legislation could result in increased operating costs, create delays in our obtaining air pollution permits for new or modified facilities, and reduce demand for the crude oil and natural gas we produce.

There are state, national and international efforts to regulate the emission of greenhouse gases including, most significantly, carbon dioxide. The U.S. Congress has considered, but has not passed, legislation that seeks to control or reduce emissions of greenhouse gases from a variety of sources. In addition, several states have taken measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories or state-specific or regional cap-and-trade programs. It is uncertain at this time whether, and in what form, climate change legislation will ultimately be adopted in the United States.

In the absence of federal legislation, the EPA is implementing regulations under the Clean Air Act pertaining to greenhouse gas emissions. In 2009, the EPA issued a finding that greenhouse gas pollution endangers the public health and welfare and subsequently finalized a greenhouse gas emission standard for mobile sources. On November 8, 2010, the EPA issued greenhouse gas monitoring and reporting regulations specifically for petroleum and natural gas facilities, including offshore petroleum and natural gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule, which went into effect on December 30, 2010, requires reporting of greenhouse gas emissions by regulated facilities to the EPA by March 2012 for emissions during 2011 and annually thereafter. The EPA issued a final rule that makes certain stationary sources and modification projects subject to permitting requirements for greenhouse gas emissions, beginning in 2011, under the Clean Air Act. Challenges to certain of those greenhouse gas rules were rejected by the D.C. Circuit Court of Appeals. Requests to reconsider are pending but, for the present, implementation seems likely although such rules may yet be modified or the EPA could develop new rules.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher greenhouse gas emitting energy sources such as coal, our products would become more desirable in the market with more stringent limitations on greenhouse gas emissions. To the extent that our products are competing with lower greenhouse gas emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on greenhouse gas emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Our operations are generally exempt from regulation by the FERC, but FERC regulations still affect our non-FERC jurisdictional businesses and the markets for products derived from these businesses. The FERC issued Order 704, which requires certain participants in the natural gas market, including interstate and intrastate pipelines, natural gas gatherers, natural gas marketers, and natural gas processors that engage in a minimum level of natural gas sales or purchases, to submit annual reports regarding those transactions.

Other FERC regulations may indirectly impact our businesses and the markets for products derived from these businesses. The FERC's policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, gas quality, ratemaking, capacity release and market center promotion, may indirectly affect the intrastate natural gas market. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot be assured that the FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to transportation capacity.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC as a natural gas company. We believe that our natural gas gathering facilities meet the traditional tests the FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission facilities and federally unregulated gathering facilities is the subject of on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by the FERC or the courts.

In addition, the courts have determined that certain pipelines that would otherwise be subject to the ICA are exempt from regulation by the FERC under the ICA as proprietary lines. The classification of a line as a proprietary line is a fact-based determination subject to FERC and court review. Accordingly, the classification and regulation of some of our gathering facilities and transportation pipelines may be subject to change based on future determinations by the FERC or the courts.

The former BOEMRE communicated that it would commence more stringent enforcement of requirements to decommission facilities that pose a hazard to safety or the environment or are not useful for lease operations and are not capable of oil and natural gas production in "paying quantities." Historically, the former BOEMRE granted approval to operators to maintain such facilities in order to conduct other future activities. However, we expect that this practice will be more limited in the future. The former BOEMRE stated that these measures were in response to recent hurricane seasons in which idle structures were damaged or destroyed. In 2011, we responded to a BOEMRE written request to review and evaluate our inventory of non-producing wells and facilities to determine the future utility of these structures and the level of threat posed to the environment and human safety in the event of a “catastrophic loss.” We periodically review our plans with the BSEE to perform wellbore plugging and abandonment and decommissioning work on certain facilities and structures in our East Bay field.

The BOEM, BSEE and other regulatory bodies, including those regulating the decommissioning of our pipelines and facilities under the jurisdiction of the state of Louisiana, may change their requirements or enforce requirements in a manner inconsistent with our expectations, which could materially increase the cost of such activities and/or accelerate the timing of cash expenditures and could have a material adverse effect on our financial position, results of operations and cash flows.

The failure to comply with these rules and regulations can result in substantial penalties, including lease termination in the case of federal leases. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations, though the impact of those requirements may vary significantly based on the nature and location of operations and related pipelines and facilities.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the EPAct of 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1.0 million per day for each violation and disgorgement of profits associated with any violation. While our systems have traditionally not been subject to full FERC regulation, the FERC's civil penalty authority may apply to a broad range of market participants that have not historically been subject to its regulations. In addition, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to annual reporting requirements. Additional rules and regulations that impact our facilities and operations may be considered or adopted by the FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability.

Our sales of oil and natural gas, and any hedging activities related to such energy commodities, expose us to potential regulatory risks.

The FERC, the Federal Trade Commission and the CFTC, hold statutory authority to monitor certain segments of the physical and futures energy commodities markets relevant to our business. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil and natural gas, and any hedging activities related to these energy commodities, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Failure to comply with such regulations, as interpreted and enforced, could materially and adversely affect our financial condition or results of operations.

The enactment of derivatives legislation by Congress could have an adverse impact on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. The CFTC has finalized a number of regulations under the Dodd-Frank Act, including critical rulemakings on the definition of "swap", "security-based swap", "swap dealer" and "major swap participant." The Dodd-Frank Act and the CFTC rules also will require us, in connection with certain derivative activities, to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption to such requirements). In addition, new regulations may require us to comply with margin requirements although these regulations are not finalized and their application to us is uncertain at this time. The CFTC, as part of its rulemaking under the Dodd-Frank Act, has also issued rules to impose position limits on certain futures and option contracts, and swaps which are the economic equivalent thereof. The subject of the proposed position limit rules includes parts of the energy market; however, the impact of these rules is uncertain at this time as the initial rules published by the CFTC were vacated by a court following litigation, and a new version of proposed rules has only recently been proposed by the CFTC and is still open for public comment until February 2014. Other regulations also remain to be finalized. As a result, it is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and the CFTC rules on us and the timing of such effects. The Dodd-Frank Act also may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), 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 Dodd-Frank Act and regulations implementing the Dodd-Frank Act, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

The proposed United States federal budget for fiscal year 2014 may include certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

To date, the Office of Management and Budget has not released a summary of the proposed United States federal budget for fiscal year 2014. When released, it is anticipated that as a result of possible significant deficit reduction or comprehensive tax reform measures currently under consideration the proposed budget may repeal many tax incentives and deductions that are currently used by United States oil and gas companies and impose new taxes. The provisions include elimination of the ability to fully deduct intangible drilling costs in the year incurred, increases in the taxation of foreign source income, repeal of the manufacturing tax deduction for oil and natural gas companies and an increase in the geological and geophysical amortization period for independent producers. Should some or all of these provisions become law, our taxes will increase, potentially significantly, which would have a negative impact on our net income and cash flows. This could also cause us to reduce our drilling activities in the United States. Since none of these proposals have yet to be voted on or become law, we do not know the ultimate impact these proposed changes may have on our business.

Cyber attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyber attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions. We have not suffered any material losses relating to such attacks; however, there is no assurance that we will not suffer such losses in the future. Although historically we have not incurred material expenditures for protective measures related to potential cyber attacks, as cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cyber attacks.

Item 1B.Unresolved Staff Comments

None.

Item 2.Properties

The information contained in Part I, Item 1, “Business” of this Annual Report is incorporated herein by reference.

Item 3.Legal Proceedings

The information contained in Note 13, “Commitments and Contingencies” in the consolidated financial statements in Part II, Item 8 of this Annual Report is incorporated herein by reference.

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

Our common stock is listed on the New York Stock Exchange (“NYSE”) under the symbol “EPL.” The following table sets forth, for the periods indicated, the range of the high and low sales prices of our common stock as reported by the NYSE.

	High ($)	Low ($)
2012		
First Quarter	18.49	14.72
Second Quarter	17.53	14.56
Third Quarter	21.99	16.01
Fourth Quarter	23.28	19.31
2013		
First Quarter	29.18	22.53
Second Quarter	35.14	26.05
Third Quarter	38.32	28.75
Fourth Quarter	42.64	25.00
2014		
First Quarter (through February 21, 2014)	31.26	25.18

On February 21, 2014, the last reported sales price of our common stock on the NYSE was $29.47 per share.

As of February 21, 2014, there were approximately 176 holders of record of our common stock.

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We have not paid cash dividends in the past on our common stock. The covenants in certain debt instruments to which we are a party, including our Senior Credit Facility and the 2011 Indenture, place certain restrictions and conditions on our ability to pay dividends. Any future cash dividends would depend on contractual limitations, future earnings, capital requirements, our financial condition and other factors determined by our board of directors.

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2013 with respect to compensation plans under which our equity securities are authorized for issuance.

Plan Category	Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights (1)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (2)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans(3)
Equity compensation plans approved by stockholders (4)	1,088,382	$ 22.56	1,184,322
Equity compensation plans not approved by stockholders (5)	809,286	$ 13.35	-
Total	1,897,668	$ 17.76	1,184,322

(1)Comprised of 1,453,173 shares subject to issuance upon the exercise of options and 444,495 shares which will vest upon the lapsing of restrictions associated with restricted share awards.

(2)Restricted share awards do not have an exercise price; therefore, this only reflects the weighted-average exercise price of options.

(3)These shares are available for future issuance under the 2009 Long Term Incentive Plan, as amended, in the form of options, appreciation rights, restricted shares, deferred shares, bonus stock and performance shares, units or restricted stock units.

(4)At our 2011 and 2013 annual meetings of stockholders, our stockholders approved increases in the number of shares authorized for issuance under the 2009 Long Term Incentive Plan from 1,237,000 shares to 3,574,000 shares.

(5)The form of the 2009 Long Term Incentive Plan was filed with the supplement to our plan of reorganization and approved by the United States Bankruptcy Court for the Southern District of Texas prior to our emergence from Chapter 11 reorganization on September 21, 2009. Accordingly, no stockholder approval was required, and none was sought or obtained.

See Note 12 “Employee Benefit Plans” of the consolidated financial statements in Part II, Item 8 of this Annual Report for further information regarding the material features of the above plan.

Stock Performance Graph

This information is being "furnished" to the SEC and is not deemed to be "soliciting material" or to be "filed" with the SEC or subject to Regulation 14A or 14C under the Exchange Act or to the liabilities of Section 18 of the Exchange Act, and will not be deemed to be incorporated by reference into any filings we make under the Securities Act of 1933, as amended, or the Exchange Act, except to the extent we specifically incorporate it be reference into such a filing.

The following graph compares the cumulative total shareholder return on our common stock relative to the cumulative total returns of (i) the Russell 2000 index, (ii) our previous peer group, which was used in 2012, and includes: ATP Oil & Gas Corporation, Energy XXI (Bermuda) Limited, McMoRan Exploration Company, Stone Energy Corporation and W&T Offshore, Inc. (the "Old Peer Group") and (iii) our new peer group, which is a customized peer group of independent oil and natural gas exploration and production companies and includes: Contango Oil & Gas Company; Energy XXI (Bermuda) Limited; PetroQuest Energy, Inc.; Stone Energy Corporation; Swift Energy Corporation and W&T Offshore, Inc. (the "New Peer Group"). We modified our peer group to remove ATP Oil & Gas Corporation, which recently filed for Chapter 11 bankruptcy protection and McMoRan Exploration Company, which was acquired in early 2013 by Freeport-McMoran Copper & Gold, a company which is more diversified than our company. Our New Peer Group consists of companies which we believe focus in a geographic area similar to ours and which we believe analysts would be more likely to compare us with for investment purposes.

The graph tracks the performance of a $100 investment in our common stock, the New Peer Group, the Old Peer Group and the Russell 2000 index (with reinvestment of all dividends) from September 30, 2009, the end of the first month in which we emerged from Chapter 11 bankruptcy proceedings, through December 31, 2013. Because the value of our old common stock bears no relation to the value of our existing common stock, the graph below reflects only our new common stock. The historic price performance is not necessarily indicative of future stock performance.

	9/30/09	12/31/09	12/31/10	12/31/11	12/31/12	12/31/13
EPL Oil & Gas, Inc	100.00	114.61	199.20	195.71	302.28	382.04
Russell 2000	100.00	103.87	131.77	126.27	146.91	203.95
Old Peer Group	100.00	116.30	176.75	118.25	111.46	131.82
New Peer Group	100.00	103.07	159.38	167.42	136.09	143.26

Item 6.Selected Financial Data

The following table shows selected financial data derived from our consolidated financial statements, which are set forth in Part II, Item 8, "Financial Statements and Supplementary Data" of this Annual Report. The data should be read in conjunction with Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" of this Annual Report.

	Successor Company					Predecessor Company (1)
	Year Ended December 31, 2013	Year Ended December 31, 2012	Year Ended December 31, 2011	Year Ended December 31, 2010	Period from October 1, 2009 through December 31, 2009	Period from January 1, 2009 through September 30, 2009
	(In thousands, except per share data)					
Statement of Operations Data:						
Revenue	$ 693,038	$ 423,633	$ 348,327	$ 239,909	$ 56,750	$ 134,885
Income (loss) from operations (2)	219,591	130,447	67,126	7,309	(4,523)	(51,323)
Net income (loss)	85,274	58,810	26,611	(8,468)	(21,012)	(36,114)
Basic earnings (loss) per common share	$ 2.18	$ 1.50	$ 0.66	$ (0.21)	$ (0.53)	$ (1.12)
Diluted earnings (loss) per common share	$ 2.15	$ 1.50	$ 0.66	$ (0.21)	$ (0.53)	$ (1.12)

	Successor Company As of December 31,				
	2013	2012	2011	2010	2009
	(In thousands)				
Balance Sheet Data:					
Total assets (2)	1,857,831	$ 1,705,627	$ 915,220	$ 626,906	$ 709,228
Long-term debt, excluding current maturities(2) (3)	627,355	689,911	204,390	-	58,590
Stockholders' equity	629,213	545,973	491,045	473,116	480,087
Cash dividends per common share	-	-	-	-	-

(1)In connection with our emergence from Chapter 11 reorganization, we adopted fresh-start accounting as of September 30, 2009. Fresh-start accounting is required upon a substantive change in control and requires that the reporting entity allocate the reorganization value of the Company to its assets and liabilities in relation to their fair values. Under the provisions of fresh-start accounting, a new entity has been deemed created for financial reporting purposes.

(2)During the year ended December 31, 2012, we acquired the Hilcorp Properties and the ST41 Interests. In connection with the Hilcorp Acquisition, we issued $300.0 million in aggregate principal amount of our 8.25% Senior Notes. During the year ended December 31, 2011, we acquired the ASOP Properties and Main Pass Interests. In connection with the ASOP Acquisition, we issued $210.0 million in aggregate principal amount of our 8.25% Senior Notes.

(3)At December 31, 2013, 2012 and 2011, none of our debt was classified as current. At December 31, 2010, we had no borrowings outstanding. At December 31, 2009 long-term debt classified as current was $18.8 million.

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

Overview

We were incorporated as a Delaware corporation in January 1998 and operate in a single segment as an independent oil and natural gas exploration and production company. Our current operations are concentrated in the U.S. Gulf of Mexico shelf focusing on state and federal waters offshore Louisiana, which we consider our core area. We have focused on acquiring and developing assets in this region, as it offers a balanced and expansive array of existing and prospective exploration, exploitation and development opportunities in both established productive horizons and deeper geologic formations. As of December 31, 2013, we had estimated proved reserves of 80.4 Mmboe, of which 64% were oil and 71% were proved developed. Of these proved developed reserves, 69% were oil reserves.

Recent Events

On January 15, 2014, we completed the Nexen Acquisition for $70.4 million, subject to customary adjustments to reflect the September 1, 2013, economic effective date. The assets we acquired include five leases in the Eugene Island 258/259 field—namely blocks 254, 255, 257, 258, and 259 (the "EI Interests"). The EI Interests are currently producing approximately 900 net Boe per day, about 95% of which is oil. Estimated proved reserves as of the September 1, 2013 effective date consisted of approximately 2.6 Mmboe of proved developed producing reserves, about 91% of which were oil. The estimated asset retirement obligation to be assumed and recorded on our balance sheet as a result of the Nexen Acquisition is expected to total approximately $27.1 million.

The Nexen Acquisition was financed with borrowings under our Senior Credit Facility. In January 2014, our lenders approved a $50.0 million increase in our borrowing base under our Senior Credit Facility, increasing our borrowing base from $425.0 million to $475.0 million. See "—Liquidity and Capital Resources—Senior Credit Facility" for more information regarding our Senior Credit Facility.

In September and October 2013, we negotiated agreements totaling approximately $45 million with seismic companies to acquire 3D seismic licenses over our core areas. These agreements include a commitment to acquire area-wide data licenses for seismic acquisitions that will be performed by the seismic company during 2014, 2015 and 2016 covering a minimum of 200 blocks, or approximately one million acres, within the shallow water Gulf of Mexico covering our core asset base.

2013 Acquisitions and Dispositions

On April 2, 2013, we sold certain shallow water Gulf of Mexico shelf oil and natural gas interests located within the non-operated Bay Marchand field (the "BM Interests") to the property operator for $51.5 million in cash and the buyer's assumption of liabilities recorded on our balance sheet of $11.3 million resulting in total consideration of $62.8 million, subject to customary adjustments to reflect the January 1, 2013 economic effective date. Our results for the year ended December 31, 2013 reflect a pre-tax gain of $28.1 million from this sale. See "—Liquidity and Capital Resources—Acquisitions and Dispositions" in this Item 2 for more information regarding the use of proceeds from this sale.

On September 26, 2013, we acquired the WD29 Interests for $21.8 million in cash, subject to customary adjustments to reflect an economic effective date of January 1, 2013 (the "WD29 Acquisition"). We estimate that the proved reserves as of the January 1, 2013 economic effective date totaled approximately 0.7 Mmboe, of which 95% were oil and 58% were proved developed reserves. The WD29 Acquisition was funded with a portion of the proceeds from the sale of the BM Interests described above.

On March 20, 2013, we were the high bidder on five leases at the Central Gulf of Mexico Lease Sale 227. The five high bid lease blocks cover a total of 13,892 acres on a gross and net basis and are all located in the shallow Gulf of Mexico within our core area of operations. Our share of the high bids totaled approximately $2.1 million. We have been awarded all five of the leases.

2012 Acquisitions

On October 31, 2012, we acquired the Hilcorp Properties for $550.0 million in cash, subject to customary adjustments to reflect an economic effective date of July 1, 2012. As of December 31, 2012, the Hilcorp Properties had estimated proved reserves of approximately 37.2 Mmboe, of which 49% were oil and 58% were proved developed reserves. The Hilcorp Properties included the three core producing complexes of the Ship Shoal 208, South Pass 78 and South Marsh Island 239 areas and related gathering lines which are described in Part I, Item 1, "Business – Properties."

The Hilcorp Acquisition was financed with cash on hand, the net proceeds from the sale of $300.0 million in aggregate principal amount of our 8.25% senior notes due 2018 (the “2012 Senior Notes”) and borrowings under our Senior Credit Facility. The 2012 Senior Notes were offered in a private placement only to qualified institutional buyers under Rule 144A promulgated under the Securities Act of 1933, as amended (the “Securities Act”), or to persons outside of the United States in compliance with Regulation S promulgated under the Securities Act. After deducting the initial purchasers’ discount, we realized net proceeds of $289.5 million. Also on October 31, 2012, we obtained an increase in the aggregate commitment under our Senior Credit Facility from $250.0 million to $750.0 million under which we borrowed $205.0 million to fund a portion of the purchase price and related expenses of the Hilcorp Acquisition.

In the June 20, 2012, Central Gulf of Mexico Lease Sale 216/222, we were the high bidder on six leases covering a total of 27,148 acres on a gross and net basis located in the shallow Gulf of Mexico shelf within our core area of operations. Our share of the high bids totaled approximately $7.0 million.

On May 15, 2012, we acquired the ST41 Interests for $32.4 million in cash, subject to customary adjustments to reflect an economic effective date of April 1, 2012 (the “ST41 Acquisition”). Prior to the ST41 Acquisition, we owned a 60% working interest in the properties, and W&T owned a 40% working interest. As a result of the ST41 Acquisition, we have become the sole working interest owner of the South Timbalier 41 field. The ST41 Interests had estimated proved reserves as of the acquisition date of approximately 1.0 Mmboe, of which 51% were oil and 84% were proved developed reserves. We funded the ST41 Acquisition with cash on hand.

2011 Acquisitions

On February 14, 2011, we acquired the ASOP Properties for $200.7 million in cash, subject to customary adjustments to reflect an economic effective date of January 1, 2011 (the "ASOP Acquisition"). On November 17, 2011, we acquired the Main Pass Interests for $38.6 million in cash, subject to customary adjustments to reflect an economic effective date of November 1, 2011 (the "Main Pass Acquisition"). The Main Pass Interests consist of additional interests in the Main Pass 296/311 complex that was included in the assets we purchased from ASOP, along with other unit interests in the Main Pass complex and an interest in a Main Pass 295 primary term lease. As of their respective acquisition dates, the ASOP Properties had estimated proved reserves of approximately 8.1 Mmboe, of which 84% were oil and 76% were proved developed reserves, and the Main Pass Interests had estimated proved reserves of approximately 1.3 Mmboe, of which 96% were oil and 100% were proved developed producing reserves.

We financed the ASOP Acquisition with the proceeds from the sale of $210.0 million in aggregate principal amount of 8.25% senior notes due 2018 (the "2011 Senior Notes"). After deducting the initial purchasers' discount and estimated offering expenses, we realized net proceeds of approximately $202.0 million from the sale of the 2011 Senior Notes. We funded the Main Pass Acquisition with cash on hand.

These acquisitions significantly increased our reserves, production volumes and drilling portfolio, while maintaining our focus on oil-weighted assets in our core area of expertise in the Gulf of Mexico shelf. They have also provided us with access to infrastructure and extensive acreage, with significant exploitation and development potential. We intend to pursue exploration and exploitation of these properties, including recompletions, well reactivations and development drilling. In conjunction with the Hilcorp Acquisition, we implemented a three-year commodity price hedging program weighted towards oil to help reduce commodity price risks associated with future oil production.

Overview and Outlook

During 2013, we spent approximately $335.9 million on development activities and exploration projects and approximately $12.3 million on seismic purchases within existing core field areas. We also spent approximately $2.1 million on the five leases at the Central Gulf of Mexico Lease Sale 227. Additionally, we spent approximately $53.3 million in 2013 on plugging, abandonment and other decommissioning activities. Our fiscal year 2014 capital budget is $360 million, which is allocated to development activities and exploration projects within existing core fields. Additionally, we plan to spend approximately $50 million in 2014 on plugging, abandonment and other decommissioning activities. We budget our capital spending on exploration and development with the goal of remaining within cash flow from operations.

We continue to generate prospects, strive to maintain an extensive inventory of drillable prospects in-house and maintain exposure to new opportunities through relationships with industry partners. We continually review and monitor opportunities to acquire producing properties, leasehold acreage and drilling prospects so that we can act quickly as acquisition opportunities become available. We intend to focus our acquisition strategy on assets in the Gulf of Mexico and the Gulf Coast region that are characterized by production-weighted reserves, seismic coverage, operated positions and the ability to consolidate interests in existing properties. We intend to use acquisitions of this type as a key method to replace and grow reserves and production because we believe this strategy increases production and cash flow while reducing dry hole and exploration risk. We believe our expertise in the Gulf of Mexico shelf and in plugging and abandonment operations allows us to effectively evaluate acquisitions and to operate any properties we eventually acquire.

Our longer term operating strategy is to increase our oil and natural gas reserves and production while focusing on exploration and development costs and operating costs to remain competitive with our offshore Gulf of Mexico industry peers.

We believe that our core competency in plugging, abandonment and decommissioning operations will enable us to achieve our objectives of prudently removing idle infrastructure throughout the remaining productive lives of our fields and, over time, to reduce ongoing lease operating expenses ("LOE") associated with maintaining idle infrastructure.

Our revenue, profitability and future growth rate depend substantially on factors beyond our control, such as oil and natural gas prices, tropical weather, economic, political and regulatory developments and availability of other sources of energy. Oil and natural gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil and natural gas could have a material adverse effect on our financial position, our results of operations, our cash flows, the quantities of oil and natural gas reserves that we can economically produce and our access to capital. See "Risk Factors" in Part I, Item 1A of this Annual Report for a more detailed discussion of these risks.

Results of Operations

The following table represents information about our oil and natural gas operations.

	Year Ended December 31,		
	2013	2012	2011
Net production (per day):			
Oil (Bbls)	16,938	10,398	8,089
Natural gas (Mcf)	32,863	17,852	17,968
Total (Boe)	22,415	13,373	11,084
Average sales prices:			
Oil (per Bbl)	$ 104.01	$ 106.08	$ 108.81
Natural gas (per Mcf)	3.81	2.89	4.11
Total (per Boe)	84.18	86.33	86.07
Oil and natural gas revenues (in thousands):			
Oil	$ 643,033	$ 403,663	$ 321,275
Natural gas	45,710	18,866	26,932
Total	688,743	422,529	348,207
Impact of derivatives instruments settled during the period (1):			
Oil (per Bbl)	$ (1.78)	$ (0.88)	$ (5.87)
Natural gas (per Mcf)	(0.04)	(0.07)	-
Average costs (per Boe):			
LOE	$ 20.27	$ 19.38	$ 17.37
Depreciation, depletion and amortization (“DD&A”)	24.49	23.21	25.86
Accretion of liability for asset retirement obligations	3.46	3.18	3.94
Taxes, other than on earnings	1.40	2.66	3.55
General and administrative (“G&A”) expenses	3.44	4.74	4.63
Increase (decrease) in oil and natural gas revenues due to:			
Changes in prices of oil	$ (7,879)	(8,055)	
Changes in production volumes of oil	247,249	90,443	
Total increase in oil sales	239,370	82,388	
Changes in prices of natural gas	$ 6,017	(7,995)	
Changes in production volumes of natural gas	20,827	(71)	
Total increase (decrease) in natural gas sales	26,844	(8,066)	

(1) See “—Other Income and Expense” section for further discussion of the impact of derivative instruments

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Overview

During the year ended December 31, 2013, we completed 16 development drilling operations, 13 of which were successful, and 21 recompletion operations, 17 of which were successful. In addition, we were 100% successful in five well operations that re-established production at existing wells, primarily within our Main Pass area. Additionally, we drilled one successful exploratory oil well in a recently-acquired primary term lease in our Main Pass 244 field that reached its target depth in September 2013 and is waiting on production facilities to commence production. One additional exploratory well that we drilled in our East Bay area during the year ended December 31, 2013 was not successful. We are currently in the process of drilling five gross (5.0 net) development wells, three in our Ship Shoal 208 field, one in our West Delta area and one in our South Timbalier area. In addition, we are currently in the process of drilling one exploratory well (0.5 net) in our Ship Shoal 208 field, which we are completing and for which we anticipate first production in April 2014.

One operating results for the year ended December 31, 2013, compared to the year ended December 31, 2012, reflect a 63% increase in oil production and an 84% increase in natural gas production. Our product mix for the year ended December 31, 2013 was 76% oil (including natural gas liquids) compared to 78% for the year ended December 31, 2012, resulting in a 68% increase in our overall production volumes for the year ended December 31, 2013 when compared to the year ended December 31, 2012.

Revenue and Net Income

	Year Ended December 31,			
	2013	2012		
	(in thousands)		$ Change	% Change
Oil and natural gas revenues	$ 688,743	$ 422,529	$ 266,214	63%
Net income	85,274	58,810	26,464	45%

For the year ended December 31, 2013, our oil and natural gas revenues increased 63% as compared to the year ended December 31, 2012, due primarily to the 63% increase in oil production, partially offset by slightly lower average selling prices for our oil. The increase in our oil and natural gas revenues also reflects the 84% increase in natural gas production and a 32% increase in average selling prices for natural gas in the year ended December 31, 2013, as compared to the year ended December 31, 2012.

Our Gulf of Mexico shelf production, excluding the Hilcorp Properties, increased 29% in the year ended December 31, 2013, as compared to the year ended December 31, 2012, due primarily to production increases in our West Delta, South Pass 49 and Main Pass fields partially offset by production declines in our South Timbalier area. Production from the Hilcorp Properties increased our production rate by approximately 5,902 Boe per day in the year ended December 31, 2013, compared to results for the year ended December 31, 2012, which include production from the Hilcorp Properties only for the period from November 1 to December 31, 2012, reflecting a 1,488 Boe per day impact on the production rate in the prior period.

In addition to the items addressed above, our net income for the year ended December 31, 2013 includes a gain on sale of assets of $28.7 million, primarily from the sale of the BM Interests; a loss on abandonment activities of $27.2 million; interest expense of $52.4 million and a net loss on derivative instruments of $32.4 million. Our net income for the year ended December 31, 2012 reflects a loss on abandonment activities of $2.4 million; interest expense of $28.6 million and a net loss on derivative instruments of $13.3 million.

For the years ended December 31, 2013 and 2012, our effective income tax rate was 36.8% and 33.7%, respectively, and the income tax expense that we recorded was all deferred. For the year ended December 31, 2012 the income tax expense that we recorded was reduced due to applying the change in our estimated effective income tax rate to our net deferred tax liabilities. The change in our estimated effective income tax rate from 37.3% in 2011 to 36.4% in 2012 was primarily related to estimated state income taxes.

Operating Expenses

Our operating expenses primarily consisted of the following:

	Year Ended December 31,	
	2013	2012

	(in thousands)		$ Change	% Change
LOE	$ 165,841	$ 94,850	$ 70,991	75%
Exploration expenditures and dry hole costs	26,555	18,799	7,756	41%
Impairments	2,937	8,883	(5,946)	-67%
DD&A, including accretion expense	228,658	129,146	99,512	77%
G&A expenses	28,137	23,208	4,929	21%
Taxes, other than on earnings	11,490	13,007	(1,517)	-12%
Other	34,942	4,678	30,264	647%

LOE increased for the year ended December 31, 2013, compared to the year ended December 31, 2012, primarily due to the acquisition of the Hilcorp Properties. LOE for the year ended December 31, 2013 also included approximately $8.2 million of non-routine workover expenses.

Exploration expenditures and dry hole costs increased for the year ended December 31, 2013, as compared to the year ended December 31, 2012, primarily reflecting costs associated with the increased size of our geological and geophysical staff. We also had increases in seismic expense and dry hole costs. For the year ended December 31, 2013, seismic expense, was $12.3 million compared to $10.6 million for the year ended December 31, 2012. Our seismic expense for the year ended December 31, 2013 relates primarily to the 3-D seismic agreements negotiated during the year. Our seismic expense for the year ended December 31, 2012 related to area-wide 2-D and 3-D seismic purchases. For the year ended December 31, 2013, we recorded approximately $5.5 million of dry hole costs, primarily associated with an exploratory drilling operation during the year which was unsuccessful. For the year ended December 31, 2012, we recorded approximately $4.2 million of dry hole costs, primarily associated with two exploratory wells which reached their target depths in January 2012 and were determined to be unsuccessful and an unsuccessful exploratory portion of a well that was successfully completed in a development zone.

Our exploratory expenditures and dry hole costs will vary significantly depending on the amount of our capital expenditures dedicated to exploration activities and the level of success we achieve in exploratory drilling activities.

Impairments for the year ended December 31, 2013 were primarily related to reservoir performance at a gas well in one of our smaller producing fields. This field was determined to have future net cash flows less than its carrying value resulting in the write down of this property to its estimated fair value during the year ended December 31, 2013. Impairments for the year ended December 31, 2012 were primarily due to the decline in our estimate of future natural gas prices, which affected three of our natural gas producing fields and reservoir performance at two of those fields. These fields were determined to have future net cash flows less than their carrying values resulting in the write down of these properties to their estimated fair values. We also recorded impairments for undeveloped leases that were expiring in 2013 for which we had no development plans. We periodically assess our oil and natural gas assets for impairment based on factors described in "—Discussion of Critical Accounting Policies." The factors that can result in impairment include declines in the estimated future selling prices of oil and natural gas.

DD&A increased for the year ended December 31, 2013, as compared to the year ended December 31, 2012, primarily due to the increase in production associated with the acquisition of the Hilcorp Properties.

G&A expenses increased for the year ended December 31, 2013, as compared to the year ended December 31, 2012, primarily as a result of higher professional fees related to the expansion of our asset base following the acquisition of the Hilcorp Properties and an increase in non-cash share-based compensation. G&A per Boe for the year ended December 31, 2013, as compared to the year ended December 31, 2012, declined significantly because of the increase in production primarily from the Hilcorp Properties.

Taxes, other than on earnings, were lower in the year ended December 31, 2013, as compared to the year ended December 31, 2012. The decrease is primarily related to severance taxes and a decrease in production from state leases (which is subject to a severance tax regime).

Other operating expenses increased for the year ended December 31, 2013, as compared to the year ended December 31, 2012, primarily as a result of an increase in loss on abandonment activities and amortization of the premium paid for our weather derivative. During the year ended December 31, 2013, we recorded loss on abandonment activities totaling $27.2 million and amortization expense related to our weather derivative of $8.0 million. During the year ended December 31, 2012, we recorded loss on abandonment activities totaling $2.4 million and amortization expense related to our weather derivative of $2.4 million. For the year ended December 31, 2013, our loss on abandonment activities primarily reflects an increase of $20.8 million in our ARO liability related to our non-operated deepwater properties.

Other Income and Expense

Interest expense increased for the year ended December 31, 2013, as compared to the year ended December 31, 2012. The increase in our interest expense is due to the full year of interest on our 2012 Senior Notes and borrowings on our Senior Credit Facility for the year ended December 31, 2013. For the year ended December 31, 2012, our interest expense included interest on our 2012 Senior Notes and interest on borrowings on the Senior Credit Facility beginning in late October 2012 in connection with the Hilcorp Acquisition.

Other income (expense) in the year ended December 31, 2013 includes a net loss on derivative instruments of $32.4 million consisting of a loss of $20.9 million due to the change in fair value of derivative instruments to be settled in the future and a loss of $11.5 million on derivative instruments settled during the period primarily from the impact of higher oil prices on our oil fixed-price swaps. Other income (expense) in the year ended December 31, 2012 includes a net loss on derivative instruments of $13.3 million consisting of a loss of $9.5 million due to the change in fair market value of derivative instruments and a loss of $3.8 million on derivative instruments settled during the period primarily from the impact of higher oil prices during 2012 on our oil fixed-price swaps.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Overview

During the year ended December 31, 2012, we completed 12 development drilling operations, 11 of which were successful, and 18 recompletion operations, 16 of which were successful. We also completed three exploratory drilling operations, one of which was successfully completed in a development zone.

Our operating results for the year ended December 31, 2012, compared to the year ended December 31, 2011, reflect a 29% increase in oil production, partially offset by lower average selling prices for our oil and natural gas. Our product mix for the year ended December 31, 2012 was 78% oil (including natural gas liquids) compared to 73% for the year ended December 31, 2011. Production from the acquired Hilcorp Properties, ST41 Interests, ASOP Properties and Main Pass Interests had an impact of approximately 6,648 Boe per day on the production rate for the year ended December 31, 2012, compared to results for the year ended December 31, 2011, which include production from the ASOP Properties for the period from February 14, 2011 to December 31, 2011, reflecting only a 3,283 Boe per day impact on the production rate in the prior period.

For the year ended December 31, 2012, our total revenue increased 22% as compared to the year ended December 31, 2011, due primarily to the 29% increase in oil production. Our overall production volumes increased 21% for the year ended December 31, 2012 when compared to the year ended December 31, 2011. Our Gulf of Mexico shelf production, excluding the recently acquired Hilcorp Properties, increased 10% in the year ended December 31, 2012, as compared to the year ended December 31, 2011, due primarily to production increases in our West Delta field and production from other ASOP Properties, the Main Pass Interests and the ST41 Interests, partially offset by production declines in our predominantly natural gas fields. The Hilcorp Properties contributed 1,488 Boe per day to our production rate for the year ended December 31, 2012, producing approximately 8,944 Boe per day from November 1, 2012 through December 31, 2012. Our deepwater production, primarily natural gas, was curtailed during the year ended December 31, 2012 due to third party downstream facility modifications.

In addition to the items addressed above, our net income for the year ended December 31, 2012 includes exploration expenditures, primarily due to area-wide 2-D and 3-D seismic purchases totaling $10.6 million, impairments of $8.9 million and a net loss on derivative instruments of $13.3 million. The net income for the year ended December 31, 2011 reflects impairments of $32.5 million, a net loss on derivative instruments of $5.9 million and a $2.4 million loss on early extinguishment of debt as a result of the termination of our prior credit facility.

Our effective income tax rate for the year ended December 31, 2012 was 33.7%. The income tax expense that we recorded (all of which was deferred) for the year ended December 31, 2012 was reduced due to applying the change in our estimated effective income tax rate to our net deferred tax liabilities. The change in our estimated effective income tax rate from 37.3% in 2011 to 36.4% in 2012 was primarily related to estimated state income taxes. The effective income tax rate for the year ended December 31, 2011 was 35.8%. The income tax expense (all of which was deferred) that we recorded for the year ended December 31, 2011 was reduced due to applying the change in our estimated effective income tax rate to our net deferred tax liabilities. The change in our estimated effective income tax rate from 37.6% in 2010 to 37.3% in 2011 was primarily related to estimated state income taxes.

Revenue and Net Income

	Year Ended December 31,			
	2012	2011		
	(in thousands)		$ Change	% Change
Oil and natural gas revenues	$ 422,529	$ 348,207	$ 74,322	21%
Net income	58,810	26,611	32,199	121%

Our oil and natural gas revenues increased primarily as a result of the 29% increase in oil production in the year ended December 31, 2012, as compared to the year ended December 31, 2011, offset in part by a 3% decline in average selling prices for our oil and a 30% decline in average selling prices for our natural gas in the year ended December 31, 2012, as compared to the year ended December 31, 2011. Oil represented 78% of total production for the year ended December 31, 2012, as compared to 73% of total production for the year ended December 31, 2011.

Operating Expenses

Our operating expenses primarily consisted of the following:

	Year Ended December 31, 2012	2011	$ Change	% Change
	(in thousands)			
LOE	$ 94,850	$ 70,281	$ 24,569	35%
Exploration expenditures and dry hole costs	18,799	14,268	4,531	32%
Impairments	8,883	32,466	(23,583)	-73%
DD&A, including accretion expense	129,146	120,566	8,580	7%
G&A expenses	23,208	18,741	4,467	24%
Taxes, other than on earnings	13,007	14,365	(1,358)	-9%
Other	4,678	9,735	(5,057)	-52%

LOE increased for the year ended December 31, 2012, compared to the year ended December 31, 2011, primarily due to the 2011 acquisitions of the ASOP Properties and Main Pass Interests and the 2012 acquisitions of the Hilcorp Properties and the ST41 Interests and approximately $3.0 million of expenses related to Hurricane Isaac in the 2012 period.

We recorded approximately $4.2 million of dry hole costs, primarily associated with two exploratory wells, which were being drilled at December 31, 2011, reached their target depths in January 2012 and were determined to be unsuccessful, and an unsuccessful exploratory portion of a well that was successfully completed in a development zone. In addition, exploration expenditures during the year ended December 31, 2012 include $10.6 million of seismic expense. We recorded approximately $11.2 million of dry hole costs associated with unsuccessful wells in the year ended December 31, 2011. In the year ended December 31, 2011, we completed drilling five exploratory wells, one of which was unsuccessful. In addition, exploration expenditures in the year ended December 31, 2011 includes $0.8 million of seismic expenditures and delay rentals.

Impairments for the year ended December 31, 2012 were primarily due to the decline in our estimate of future natural gas prices, which affected three of our natural gas producing fields and reservoir performance at two of those fields. These fields were determined to have future net cash flows less than their carrying values resulting in the write down of these properties to their estimated fair values. We also recorded impairments for undeveloped leases that are expiring in 2013 for which we had no development plans. Impairments for the year ended December 31, 2011 were primarily related to natural gas producing fields and our deepwater producing well (primarily natural gas). Impairments related to our deepwater producing well were primarily due to the decline in our estimate of future natural gas prices, reservoir performance and higher estimated operating costs. Additional impairments for the year ended December 31, 2011 were primarily related to reservoir performance at other natural gas producing fields.

G&A expenses increased for the year ended December 31, 2012, as compared to the year ended December 31, 2011, primarily as a result of an increase in employee-related costs, including an increase in non-cash share-based compensation, which was $4.7 million in the 2012 period as compared to $2.5 million in the year ended December 31, 2011.

Taxes, other than on earnings, were lower in the year ended December 31, 2012, as compared to the year ended December 31, 2011. The decrease is primarily related to severance taxes and a decrease in production from state leases (which is subject to a severance tax regime).

Other Income and Expense

Interest expense increased in the year ended December 31, 2012, as compared to the year ended December 31, 2011. For the year ended December 31, 2012, our interest expense included interest on our 2012 Senior Notes and the Senior Credit Facility since the time of the issuance of the 2012 Senior Notes and borrowings on the Senior Credit Facility during late October 2012 in connection with the Hilcorp Acquisition as well as interest on the 2011 Senior Notes. For the year ended December 31, 2011, our interest expense consisted primarily of interest on our 2011 Senior Notes issued on February 14, 2011 in connection with the ASOP Acquisition.

Other income (expense) in the year ended December 31, 2012 includes a net loss on derivative instruments of $13.3 million consisting of a loss of $9.5 million due to the change in fair market value of derivative instruments and a loss of $3.8 million on derivative instruments settled during the period primarily from the impact of higher oil prices during 2012 on our oil fixed-price swaps. Other income (expense) in the year ended December 31, 2011 includes a net loss of $5.9 million consisting of a gain of $11.5 million due to the change in fair market value of derivative instruments and a loss of $17.4 million on derivative instruments settled during the period primarily from the impact of higher oil prices during 2011 on our oil fixed-price swaps.

Liquidity and Capital Resources

Sources and Uses of Capital

As of February 21, 2014, we had $265.0 million available under our Senior Credit Facility, which has a borrowing base of $475.0 million. During January 2014, we borrowed $58.0 on our Senior Credit Facility to fund a portion of the Nexen Acquisition and we currently have $210.0 million outstanding under our Senior Credit Facility. During the year ended December 31, 2013, we reduced our borrowings under this facility to $130.0 million, a reduction of $65.0

million since December 31, 2012. Of the net proceeds of $51.5 million from the sale of our BM Interests, approximately $16.5 million was used to fund the WD29 Acquisition and approximately $35.0 million was used in this reduction of borrowings.

Our fiscal year 2014 capital budget is $360 million, which is allocated to development activities and exploration projects within existing core field areas. Additionally, we plan to spend approximately $50 million in 2014 on plugging, abandonment and other decommissioning activities. We intend to finance our capital budget with cash flow from operations. However, we may borrow under our Senior Credit Facility, as needed.

Cash Flow and Working Capital. Net cash provided by operating activities increased to $387.6 million for the year ended December 31, 2013 compared to $213.9 million and $171.3 million for the years ended December 31, 2012 and 2011, respectively. Based on our outlook of commodity prices and our estimated production, we expect to fund our 2014 capital expenditures with cash flow from operations and borrowings under our Senior Credit Facility, as needed.

Our revenue, profitability, cash flows and future growth are substantially dependent upon prevailing and future prices for oil and natural gas, each of which depends on numerous factors beyond our control such as economic conditions, regulatory developments and competition from other energy sources. Oil and natural gas prices historically have been volatile, and may be subject to significant fluctuations in the future. Our derivative instruments serve to mitigate a portion of this price volatility on our cash flows. For full year 2014, we have a total of 12,996 Bbls of oil per day hedged, all of which is hedged using Louisiana Light Sweet ("LLS") fixed price swaps at a price averaging $93.67 per Bbl. We have a total of 5,000 Mmbtu of natural gas per day hedged for 2014, all of which is hedged using fixed price swaps at a price averaging $4.01 Mmbtu per day. In addition, we have begun hedging forecasted 2015 production with 1,500 Bbls of oil per day currently hedged using Brent fixed price swaps at a price of $97.70 per Bbl and 4,300 Mmbtu of natural gas per day currently hedged using fixed price swaps at a price averaging $4.31 Mmbtu per day. During 2013, we converted our outstanding 2014 oil fixed price swaps from Brent to LLS in order to more closely reflect the expected differential between the underlying prices and actual prices we receive.

We have incurred, and will continue to incur, capital expenditures to achieve production targets. While we expect to fund the majority of future capital expenditures with cash flow from operations, we depend on the availability of borrowings under our Senior Credit Facility as a source of liquidity, including for short-term working capital requirements. Based on anticipated oil and natural gas prices and availability under our Senior Credit Facility, we expect to be able to fund our planned capital expenditures budget, debt service requirements and working capital needs for 2014. In addition to borrowings under our Senior Credit Facility, in order to meet capital requirements, which could include the funding of future acquisitions, we may also have the ability to issue debt and equity securities under our universal shelf registration statement that became effective under the Securities Act in July 2011. However, a substantial or extended decline in oil or natural gas prices could have a material adverse effect on our financial position, results of operations, cash flows and quantities of oil and natural gas reserves that may be economically produced. Any such extended decline could also have an adverse impact on our ability to issue additional debt or equity securities and our ability to comply with the financial covenants under our Senior Credit Facility, which in turn would limit further borrowings under our Senior Credit Facility.

At December 31, 2013, we had a working capital deficit of $176.0 million, compared to $106.3 million at December 31, 2012. The increase in our working capital deficit as of December 31, 2013 is primarily due to the continued use of cash to repay borrowings under our Senior Credit Facility, which is classified as long-term debt, increased accounts payable and accrued expenses related to exploration and development costs, the increase in the current portion of our asset retirement obligations and an increase in the current liability associated with our derivative instruments. The working capital deficit at December 31, 2012 was primarily due to the use of cash to fund a portion of the Hilcorp Acquisition, increased accounts payable and accrued expenses related to exploration and development costs. We have experienced, and expect to experience in the future, significant working capital deficits. Our working capital deficits have historically resulted from increased accounts payable and accrued expenses related to ongoing exploration and development costs, which may be capitalized as noncurrent assets, or increased investment in oil and natural gas properties. Additionally, we expect to use any available free cash flow to reduce our debt, all of which is long-term. Therefore, although we may continue to experience working capital deficits, we expect to have significant availability under our Senior Credit Facility, providing substantial liquidity.

Capital Expenditures. During the year ended December 31, 2013, we incurred costs of approximately $335.9 million on development and exploration activities and a total of $12.3 million on seismic purchases. In addition, we spent approximately $53.3 million on plugging, abandonment and other decommissioning activities during the year ended December 31, 2013. During the year ended December 31, 2013, we recorded a revision increasing our ARO liability by $20.8 million related to our only remaining four non-producing wellbores in our non-operated deepwater properties. These increased abandonment costs are primarily attributable to changes in regulatory interpretations and enforcement by BSEE in the deepwater that increased the required scope of work. During the year ended December 31, 2013, we also recorded revisions netting to an increase in our ARO liability related to our shallower-water assets of $3.8 million. Additionally, these factors may impact our future plans to allocate capital to abandonment and decommissioning activities, and we may reduce or curtail these activities resulting in changes to our previous estimates of timing of future cash flows.

The BOEM, the BSEE and other regulatory bodies, including those regulating the decommissioning of our pipelines and facilities under the jurisdiction of the state of Louisiana, may change their requirements or enforce requirements in a manner inconsistent with our expectations, which could materially increase the cost of such activities and/or accelerate the timing of cash expenditures and could have a material adverse effect on our financial position, results of operations and cash flows. For important additional information regarding risks related to our regulatory environment, see Part I, Item 1A, "Risk Factors."

Acquisitions and Dispositions. On January 15, 2014, we completed the Nexen Acquisition for $70.4 million, which was financed with borrowings under our Senior Credit Facility. During January 2014, we requested and received, with the approval of our lenders, a $50.0 million increase in our borrowing base, bringing our borrowing base under the Senior Credit Facility to $475.0 million.

On April 2, 2013, we sold our BM Interests to the property operator for $51.5 million in cash and the buyer's assumption of liabilities recorded on our balance sheet of $11.3 million resulting in total consideration of $62.8 million, subject to customary adjustments to reflect the January 1, 2013 economic effective date. We recognized a pre-tax gain of $28.1 million.

The cash proceeds from this sale of assets were deposited with a qualified intermediary in contemplation of a potential tax-deferred exchange of properties and initially classified as restricted cash. On September 26, 2013, $16.5 million of these proceeds were used to fund the WD29 Acquisition, which was a qualifying purchase for tax-deferred purposes. On September 29, 2013, the underlying escrow agreement expired, and the remaining amount of the deposit became unrestricted.

We allocate capital in a rigorous and disciplined manner intended to achieve an overall lower risk capital expenditure profile that focuses on maximizing rate of return and requires projects to compete on that basis. This allocation has led us to focus on oil-weighted projects, resulting in a trend of increasing oil production. From time to time, we may decide to divest of certain oil and gas properties that do not meet our capital expenditure risk, rate of return, operational control or other criteria. In addition to the sale of the non-operated BM Interests, we continue to assess whether there would be any interest for other small packages of our assets. However, there can be no assurance that any such small asset packages will be sold or, if so, on what terms.

Share Repurchase Program. In August 2011, the board of directors authorized a program for the repurchase of our outstanding common stock for up to an aggregate cash purchase price of $20.0 million and increased the program to $80.0 million in July 2013. Under the program, we have repurchased 1,799,000 shares at an aggregate cash purchase price of approximately $29.7 million, including 333,700 shares purchased for approximately $9.6 million during 2013. Such shares are held in treasury and could be used to provide available shares for possible resale in future public or private offerings and our employee benefit plans. The repurchases have been, and will be, carried out in accordance with certain volume, timing and price constraints imposed by the SEC's rules applicable to such transactions. The amount, timing and price of purchases otherwise depend on market conditions and other factors, including restrictions under our Senior Credit Facility. In July 2013, our Senior Credit Facility was amended to increase the limit applicable to certain restricted payments, which includes share repurchases, permitted by the agreement.

Restricted Cash. We maintain restricted escrow funds in a trust for future plugging, abandonment and other decommissioning costs at our East Bay field. As of December 31, 2013, we had $6.0 million remaining in restricted escrow funds in the trust for decommissioning work in our East Bay field, which will remain restricted until substantially all required decommissioning in the East Bay field is complete. Amounts on deposit in the trust account are reflected in Restricted cash on our consolidated balance sheets.

8.25% Senior Notes. The 8.25% Senior Notes consist of $510.0 million in aggregate principal amount issued under the 2011 Indenture. The 8.25% Senior Notes bear interest from the date of their issuance at an annual rate of 8.25% with interest due semi-annually, in arrears, on February 15th and August 15th of each year. The 8.25% Senior Notes are fully and unconditionally guaranteed, jointly and severally, on an unsecured senior basis initially by each of our existing direct and indirect domestic subsidiaries (other than immaterial subsidiaries). The 8.25% Senior Notes will mature on February 15, 2018.

We issued the 8.25% Senior Notes in two different private placements as follows. On February 14, 2011, we issued $210.0 million in aggregate principal amount of the 2011 Senior Notes under the 2011 Indenture. We used the net proceeds from the offering of the 2011 Senior Notes of $202.0 million, after deducting the initial purchasers' discount and offering expenses payable by us, to acquire the ASOP Properties for a purchase price of $200.7 million, before adjustments to reflect an economic effective date of January 1, 2011, and for general corporate purposes.

On October 25, 2012, we issued $300.0 million in aggregate principal amount of the 2012 Senior Notes under an indenture dated as of October 25, 2012 (the "2012 Indenture"). We used the net proceeds from the offering of the 2012 Senior Notes of $289.5 million, after deducting the initial purchasers' discount, to fund a portion of the Hilcorp Acquisition. The 2012 Senior Notes were offered in a private placement only to qualified institutional buyers under Rule 144A promulgated under the Securities Act, or to persons outside of the United States in compliance with Regulation S promulgated under the Securities Act. The 2012 Senior Notes had terms that were substantially identical to the terms of our 2011 Senior Notes. Pursuant to a registration rights agreement executed as part of the sale of the

2012 Senior Notes (the “Registration Rights Agreement”), during 2013 we issued publicly registered additional notes under our 2011 Indenture in exchange for the 2012 Senior Notes. As a result of this exchange offer, 100% in aggregate principal amount of the 2012 Senior Notes was exchanged for notes under the 2011 Indenture, effective as of June 10, 2013. All of the 8.25% Senior Notes are now issued under the 2011 Indenture, regardless of which private placement they were issued under. For more information on our 8.25% Senior Notes, see Note 7, “Indebtedness,” of our consolidated financial statements contained in Part II, Item 8 of this Annual Report.

Senior Credit Facility. On February 14, 2011, we entered into our Senior Credit Facility with BMO Capital Markets, as lead arranger, and Bank of Montreal, as administrative agent and a lender, and the other lender parties thereto. The terms of our Senior Credit Facility established a revolving credit facility with a four-year term that could be used for revolving credit loans and letters of credit. On October 31, 2012, in connection with the Hilcorp Acquisition, through an amendment and restatement of our Senior Credit Facility, the aggregate commitment under this facility was increased from a maximum of $250.0 million to a maximum of $750.0 million and the maturity date was extended to October 31, 2016. The maximum amount of letters of credit that may be outstanding at any one time is $20.0 million. The amount available under the revolving credit facility is limited by the borrowing base. The Senior Credit Facility is secured by substantially all of our assets, including (a) mortgages on at least 80% of the total value of our oil and gas properties evaluated in the most recently completed reserve report, after giving effect to exploration and production activities, acquisitions and dispositions, and (b) the stock of certain wholly-owned subsidiaries. The borrowing base under our Senior Credit Facility has been determined at the discretion of the lenders, based on the collateral value of our proved reserves and is subject to potential special and regular semi-annual redeterminations. On October 31, 2012, the borrowing base under the expanded credit facility was increased from $200.0 million to $425.0 million. In January 2014, our lenders approved a $50.0 million increase in our borrowing base under the facility, increasing our borrowing base to $475.0 million. In addition, in July 2013, our Senior Credit Facility was amended to increase the limit applicable to certain restricted payments (specifically, share repurchases) permitted by the agreement. Borrowings under our Senior Credit Facility bear interest ranging from a base rate plus a margin of 0.75% to 1.75% on base rate borrowings and LIBOR plus a margin of 1.75% to 2.75% on LIBOR borrowings. Commitment fees ranging from 0.375% to 0.50% are payable on the unused portion of the borrowing base. We had $130.0 million outstanding under our Senior Credit Facility as of December 31, 2013. As of February 21, 2014, we had $210.0 million outstanding and $265.0 million in availability under our Senior Credit Facility.

Terminated Credit Facility. On February 14, 2011, we terminated the then existing credit facility in connection with entering into our current credit facility described above, resulting in a loss on early extinguishment of debt of $2.4 million, primarily due to writing off the unamortized deferred financing costs associated with the terminated facility.

Analysis of Cash Flows for the Year Ended December 31, 2013

The following table sets forth our cash flows:

	Years Ended December 31,	
	2013	2012
	(In thousands)	
Net cash provided by operating activities	$ 387,559	$ 213,871
Net cash used in investing activities	(306,339)	(764,965)
Net cash provided by (used in) financing activities	(73,929)	472,487

The increase in our 2013 cash flows from operating activities primarily reflects increases in revenues due to the increase in our oil and natural gas production during the year ended December 31, 2013, as compared to the year ended December 31, 2012.

Net cash used in investing activities decreased for the year ended December 31, 2013, as compared to the year ended December 31, 2012. Net cash used during the year ended December 31, 2013, related to an increase in exploration and development expenditures of $137.2 million compared to the year ended December 31, 2012, which is consistent with our increased capital expenditures budget for 2013. In addition, net cash used in investing activities during the year ended December, 2013 is net of the $51.7 million in proceeds from the sale of the BM Interests partially offset by property acquisitions, while the year ended December 31, 2012 includes the Hilcorp Acquisition and the acquisition of the ST41 Interests.

Net cash used in financing activities during the year ended December 31, 2013 primarily reflects repayments of $65.0 million borrowed under our Senior Credit Facility as well as $9.6 million for purchases of shares of our common stock (which are held as treasury shares) pursuant to our repurchase program. Net cash provided by financing activities during the year ended December 31, 2012 reflects $294.3 million of net cash proceeds from the issuance of the 2012 Senior Notes (including $4.8 million of accrued interest included in the purchase price of the 2012 Senior Notes) and

$215.0 million in borrowings under our Senior Credit Facility, partially offset by repayments of $20.0 million on our Senior Credit Facility, expenditures of $8.5 million for financing costs primarily associated with our Senior Credit Facility and offering expenses associated with our 2012 Senior Notes and $8.8 million for settlements of purchases of shares of our common stock (which have been kept as treasury shares) pursuant to our repurchase program.

We have not paid any cash dividends in the past on our common stock. The covenants in certain debt instruments to which we are a party, including our Senior Credit Facility and the 2011 Indenture governing the 8.25% Senior Notes, place certain restrictions and conditions on our ability to pay dividends. Any future cash dividends would depend on contractual limitations, future earnings, capital requirements, our financial condition and other factors determined by our board of directors.

Analysis of Cash Flows for the Year Ended December 31, 2012

The following table sets forth our cash flows:

	Years Ended December 31,	
	2012	2011
	(In thousands)	
Net cash provided by operating activities	$ 213,871	$ 171,252
Net cash used in investing activities	(764,965)	(310,591)
Net cash provided by (used in) financing activities	472,487	185,914

The increase in our 2012 cash flows from operating activities primarily reflects increases in revenues due to the increase in our oil production, partially offset by decreases in natural gas revenues during the year ended December 31, 2012, as compared to the year ended December 31, 2011.

Net cash used in investing activities increased in the year ended December 31, 2012, as compared to the year ended December 31, 2011, primarily due to our acquisitions of the Hilcorp Properties and the ST41 Interests during the year ended December 31, 2012. In addition, our exploration and development expenditures were higher in the year ended December 31, 2012, due to our higher 2012 capital expenditures budget. These increases were partially offset by our acquisitions of the ASOP Properties and Main Pass Interests during the year ended December 31, 2011.

Net cash provided by financing activities during the year ended December 31, 2012 reflects $294.3 million of net cash proceeds from the issuance of the 2012 Senior Notes (including $4.8 million of accrued interest included in the purchase price of the 2012 Senior Notes) and $215.0 million in borrowings under our Senior Credit Facility, partially offset by repayments of $20.0 million on our Senior Credit Facility, expenditures of $8.5 million for financing costs primarily associated with our Senior Credit Facility and offering expenses associated with our 2012 Senior Notes and $8.8 million for settlements of purchases of shares of our common stock (which have been kept as treasury shares) pursuant to our repurchase program. Net cash provided by financing activities during the year ended December 31, 2011 reflects $203.8 million of net cash proceeds (before offering expenses of $1.8 million) from the issuance of the 2011 Senior Notes, partially offset by expenditures of $6.6 million for financing costs primarily associated with our Senior Credit Facility and offering expenses associated with the 2011 Senior Notes. During the year ended December 31, 2011, we also spent $11.4 million for settlements of purchases of shares of our common stock (which have been kept as treasury shares) pursuant to our repurchase program.

Inflation

Prior to the third quarter of 2008, we observed a general rise in the selling prices of our oil and natural gas over the prior three year period due to market factors that include the decline in the value of the U.S. dollar against other currencies, including those from which the U.S. imports oil. During that same period, we also observed increasing prices for drilling services, transportation services and raw materials, such as steel, which have impacted our lease operating expenses and our capital expenditures. The significant decline in commodity prices that occurred in the latter part of 2008, along with a general economic downturn, generally created temporary downward pressure in 2009 on prices for the materials and services that we use in our operations, primarily our exploration, development, plugging, abandonment and other decommissioning activities. The cost of these materials and services has returned to higher levels due to sustained higher oil prices and the reallocation of capital and related equipment to onshore drilling activities. The duration and extent of future price changes, declines or increases, is highly uncertain.

Disclosures about Contractual Obligations and Commercial Commitments

The following table aggregates the contractual commitments and commercial obligations which affect our financial condition and liquidity position as of December 31, 2013.

	Payments Due by Period				
		Less than			More than
	Total	1 Year	1-3 Years	3-5 Years	5 years
	(in thousands)				
Long-term debt	$ 640,000	$ -	$ 130,000	$ 510,000	$ -
Interest on indebtedness	197,801	44,896	89,792	63,113	-
Operating leases	5,143	1,073	2,461	1,203	406
Asset retirement obligations (undiscounted)	595,697	95,978	39,861	11,735	448,123
Seismic data commitments (1)	40,500	13,000	20,000	7,500	-
Total contractual obligations	$ 1,479,141	$ 154,947	$ 282,114	$ 593,551	$ 448,529

(1) Represents pre-commitments for seismic data purchases.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements as of December 31, 2013, other than the operating leases disclosed above.

Derivative Instruments

Note 1 “Organization and Summary of Significant Accounting Policies” and Note 9 “Derivative Instruments and Hedging Activities,” respectively, of our consolidated financial statements contained in Part II, Item 8 of this Annual Report describe our commodity price risks and the instruments we use to manage them.

We enter into derivative instruments to reduce our exposure to fluctuations in the market prices of oil and natural gas. Hedging transactions can expose us to risk of financial loss if, among other things, production is less than expected, the counterparty to the contract defaults on its obligations, or there is a change in the expected differential between the underlying price in the derivative instrument and actual price received. Derivative instruments may limit the benefit we would have otherwise received from increases in the sales prices of our oil and natural gas. Conversely, if we were not to engage in hedging transactions, we may be more adversely affected by declines in oil and natural gas prices than our competitors who do engage in hedging transactions.

Our revenues, profitability, cash flows and future growth are highly dependent on prices for oil and natural gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under our Senior Credit Facility is subject to periodic redetermination based in part on changing expectations of future prices. Lower prices may also reduce the amount of oil and natural gas that we can economically produce. We currently sell all of our oil and natural gas production under price sensitive or market price contracts.

Discussion of Critical Accounting Policies

In preparing our financial statements in accordance with accounting principles generally accepted in the United States, management must make estimates and assumptions related to the reporting of assets, liabilities, revenues, and expenses and the disclosure of contingent assets and liabilities. Application of certain of our accounting policies requires a significant number of estimates. These accounting policies are described below.

•Successful-Efforts Method of Accounting—Oil and natural gas exploration and production companies choose from two acceptable methods of accounting for oil and gas properties, the “successful efforts” method, which is the method we use, and the “full cost” method. The most significant difference between the two methods relates to the accounting treatment of drilling costs incurred on unsuccessful exploratory wells (dry holes) and exploration costs. Under the successful efforts method of accounting for oil and natural gas producing activities, costs to acquire mineral interests in oil and natural gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. We may capitalize exploratory well costs beyond one year if (a) we found a sufficient quantity of reserves to justify its completion as a producing well and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project; otherwise, these costs are expensed. Geological and geophysical costs are charged to expense as incurred. We allocate the capitalized cost of producing oil and gas properties to earnings through DD&A on a field-by-field basis as production occurs. Seismic, geological and geophysical, and delay rental expenditures are expensed as incurred. We conduct many of our exploration and development activities jointly with others and, accordingly, recorded amounts for our oil and natural gas properties reflect only our proportionate interest in such activities. Entities that follow the full cost method capitalize drilling and exploratory costs, including dry hole costs, into one or more large pools of oil and natural gas property costs. Under the full cost method, the capitalized costs for each pool are allocated to earnings through DD&A based on the production of each pool. Additionally, under the successful efforts method, we measure impairments of our oil and natural gas properties based on the estimated fair value of oil and natural gas properties on a field-by-field basis based on the requirements of ASC Topic 360, "Property, Plant and Equipment" ("ASC 360"). In estimating fair value, we make assumptions about factors that have a high degree of uncertainty, including expected future sales prices for oil and natural gas, expected future costs of production, development and abandonment, and the appropriate rate at which we discount future cash flows. Under the full cost method, impairments are measured based on criteria determined by the SEC, which differs from the application of ASC 360.

We believe that companies with active exploratory drilling programs typically incur dry hole costs. To the extent that we incur significant amounts of exploratory drilling costs in the future, we expect to continue to incur dry hole costs in the future. We expect our dry hole costs will vary depending on our success rate in finding productive oil and natural gas reserves as well as the amount of our capital expenditures that are dedicated to exploration activities.

•Proved Reserve Estimates—We use our oil and natural gas proved reserve estimates to calculate our DD&A. We allocate the capitalized cost of our producing oil and natural gas properties to earnings through DD&A based on Boe units produced during the period as a percentage of total estimated Boe reserves. We estimate the timing of settlements of asset retirement obligations using proved reserve estimates. Changes in the estimated lives of our producing properties based on proved reserve estimates may materially impact the amount of asset retirement obligations we record due to the significance of the inflation and discount rate assumptions over the relatively long lives of many of our core fields. (See "Asset Retirement Obligations" below.) We also use reserve estimates, which may include (on a risk adjusted basis) reserves that are not proved reserves, to assess our productive oil and natural gas properties for impairment. Proved reserves are the estimated quantities of crude oil, natural gas and NGLs that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, estimated prices and costs as of the date the reserve estimates are made are held constant for the life of the reserves.

Independent reserve engineers prepare our oil and natural gas reserve estimates using guidelines established by the SEC and U.S. generally accepted accounting principles ("GAAP"). The quality and quantity of data, the interpretation of data, the accuracy of economic assumptions, and judgments and estimates regarding uncertain events and circumstances by us and our independent reserve engineers affect the accuracy of reserve estimates. We may materially revise our reserve estimates in subsequent periods due to drilling or production results or other data obtained after the date of the estimate.

As of December 31, 2013, we had estimated proved reserves of 80.4 Mmboe, of which 42% were proved developed producing reserves while 29% of our proved reserves were classified as proved developed non-producing reserves. Most of our proved developed non-producing reserves are classified as "behind pipe" and will be produced after depletion of another productive zone in the same well. Approximately 29% of our total proved reserves as of December 31, 2013 are categorized as proved undeveloped reserves.

The present value of the future net cash flows disclosed in this Annual Report is not intended to reflect the market value of the oil and natural gas reserves. In accordance with ASC 932, we use prices based on the unweighted, arithmetic average of the closing price on the first day of each of the twelve months during the fiscal year, and costs determined on the date of the estimate held constant for the life of the reserves and a 10% discount rate to determine the present value of future net cash flow. Actual costs incurred and prices received in the future may vary significantly and the discount rate may not accurately reflect economic conditions.

As of December 31, 2013, the computation of the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves used an oil price based on the NYMEX WTI of $105.30 per barrel and a natural gas price based on the NYMEX Henry Hub of $3.73 per Mcf, computed by applying the use of physical pricing based on the unweighted, arithmetic average of the closing price on the first day of each of the twelve months during the fiscal year (as required by ASC 932), applying historical adjustments, including transportation, quality differentials, and purchaser bonuses, on an individual property basis, to the year-end quantities of estimated proved reserves. The historical adjustments applied to the computed prices are determined by comparing our historical realized price experience with the comparable historical market, or posted, price. These adjustments can vary significantly over time both in amount and as a percentage of the posted price, especially related to our oil prices during periods when the market price for oil varies widely. The price adjustments reflected in our computed reserve prices may not represent the amount of price adjustments we may actually obtain in the future when we sell our production. We estimated the costs based primarily on our actual historical costs incurred for appropriate periods of time for individual properties. Where a particular property does not have production during the year, we apply pricing adjustments based on the most similar property.

•Depletion, Depreciation and Amortization of Oil and Natural Gas Properties—We calculate DD&A using the estimates of proved oil and natural gas reserves previously discussed in these critical accounting policies. We segregate the capitalized costs and record DD&A for capitalized property costs separately using the units-of-production method. The units-of-production method is based on the ratio of (1) actual volumes in barrel equivalents produced to (2) total proved developed reserve volumes in barrel equivalents (those proved reserves recoverable through existing wells with existing equipment and operating methods), or total proved reserve volumes in barrel equivalents in the case of leasehold costs. Each period, this ratio, referred to as the DD&A rate, is applied to the applicable capitalized asset cost category, resulting in allocation of the cost of our oil and natural gas properties over the periods during which they produce revenues. Because we convert our natural gas reserves and production into barrel equivalents using six thousand cubic feet of natural gas equal to one barrel of oil, which is based on the relative energy content of natural gas and oil, the margin between the revenues realized per barrel equivalent unit of production sold compared to the DD&A recorded per unit of production may vary significantly as the mix of production varies and the relative prices of natural gas and oil vary. These variations may cause our net income to change significantly over the life of our reserves and could result in future impairments. As previously discussed, material revisions to proved reserves may occur as a result of unforeseen factors and may materially impact the DD&A rate.

Our past revisions have had minimal impact on our DD&A rates because they have been relatively low as a percentage of our reserve base and/or related to fields with little cumulative production. Historical revisions are not necessarily indicative of potential future revisions.

•Impairment of Oil and Natural Gas Properties—We evaluate our capitalized oil and natural gas property costs for potential impairment when circumstances indicate that the carrying value may not be recoverable. Because we accumulate capitalized costs, and calculate DD&A, separately on a property by property (generally analogous to a field or a lease) basis, for our proved oil and natural gas properties under the successful efforts method of accounting, we perform impairment assessments on a property by property basis. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserve volumes, actual operating and development costs in excess of expected amounts, changes in estimates of future operating and capital expenditure requirements, or other changes to contracts or environmental regulations. In general, we do not view temporarily low oil or natural gas prices as a triggering event for conducting impairment tests. Historically, our sales price for oil and natural gas has varied significantly. Although our sales prices may rise and fall quickly over short periods of time, we believe sales prices over the long-term are primarily based on supply and demand factors. Accordingly, our impairment tests make use of long-term sales price assumptions for oil and natural gas. A significant amount of judgment and uncertainty is involved in performing impairment evaluations because major inputs to the computation are based on our estimates of future events, including projections of future oil and natural gas sales prices, amounts of recoverable oil and natural gas reserves, timing of future production, future costs to develop and produce our oil and natural gas and discount factors.

Our assessment of possible impairment of proved oil and natural gas properties is based on our best estimate of future prices, costs and expected net future cash flows by property. An impairment loss is indicated if undiscounted net future cash flows are less than the carrying value of a property. The impairment expense is measured as the shortfall between the net book value of the property and its estimated fair value measured based on the discounted net future cash flows from the property. Actual prices, costs, and net future cash flows may vary from our estimates. Our discount rate may not accurately reflect economic conditions. We recognized impairments of $2.9 million, $8.9 million and $32.5 million in the years ended December 31, 2013, 2012 and 2011, respectively.

For individual unevaluated properties (those with no corresponding proved reserves) with capitalized cost below a threshold amount, we allocate capitalized costs to earnings generally over the primary lease terms. We believe this method provides a reasonable estimate of the amount of capitalized costs of unevaluated properties which will prove unproductive over the primary lease terms. Properties that are subject to amortization and those with capitalized costs greater than the threshold amount are assessed for impairment periodically. If we find oil and natural gas reserves sufficient to justify development of the property, we transfer the net capitalized cost of the unproved property to proved properties and DD&A is recorded on the units-of-production basis described above. If our efforts do not result in proved oil and natural gas reserves, the related net capitalized costs are charged to earnings as impairment expense.

•Asset Retirement Obligations ("AROs")—We have material obligations to plug and abandon oil and natural gas wells and to decommission related platforms, pipelines and equipment as well as to dismantle and abandon facilities when they are no longer being used for the production of oil and natural gas. We record a liability for the estimated fair value of a material ARO in the period when we identify or incur the obligation. When the liability is initially recorded, we capitalize the cost by increasing the carrying amount of the related asset, which is allocated to expense through DD&A on the units-of-production basis. Accretion increases the ARO liability over time, using the effective interest rate method.

Numerous estimates, assumptions and judgments are inherent in the calculation of ARO including ultimate settlement amounts, timing of settlements, technological changes, future inflation rates, the credit adjusted risk-free rate of interest, and changes in legal, regulatory, environmental and political environments. We revise our estimates of ARO as information about material changes to the liability becomes known. Revisions are recorded as an adjustment to existing ARO liabilities and to the carrying amount of the related assets. Revisions occurring at or near the end of an asset's useful life may result in impairments or losses and could materially impact earnings.

•Derivative Instruments and Hedging Activities—We enter into hedging transactions for our oil and natural gas production to reduce our exposure to fluctuations in the prices of oil and natural gas. Historically, our hedging instruments have consisted primarily of financially-settled swaps and collars. We record our hedging instruments at estimated fair market value as either assets or liabilities in our consolidated balance sheet. We estimate the fair value of hedging instruments based on estimated future commodity prices. The fair market value may differ from actual settlements if market prices change, the other party to the contract defaults on its obligations, or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

•Share-Based Compensation—We measure compensation expense for all share-based payment awards based on their estimated grant-date fair values. We use the Black-Scholes option pricing model to estimate fair values of share-based awards. Option pricing models, including the Black-Scholes model, require the use of input estimates and assumptions, including expected volatility, expected life, expected dividend rate, and expected risk-free rate of return. The assumptions for expected volatility and expected life most significantly affect the estimated grant-date fair value. Our estimate of the forfeiture rate of our share-based awards also impacts the timing of expense recorded over the vesting period of the award. See Note 12, "Employee Benefit Plans," in Part II, Item 8 of this Annual Report for a description of methods used to determine our assumptions. If we determined that another method used to estimate expected volatility or expected life was more reasonable than our current methods, or if another method for calculating these input assumptions was prescribed by authoritative guidance, the estimated fair value calculated for share-based awards could change significantly. Higher volatility and longer expected lives result in increases to share-based compensation determined at the date of grant.

•Deferred Tax Asset Valuation Allowance—We are required to assess whether it is more likely than not that we will be able to realize some or all of our deferred tax assets. If we cannot determine that deferred tax assets are more likely than not recoverable, we are required to provide a valuation allowance against those assets. This assessment takes into account factors including: (a) the nature, frequency, and severity of current and cumulative financial reporting losses; (b) sources of estimated future taxable income; and (c) tax planning strategies. A pattern of recent financial reporting losses is heavily weighted as a source of negative evidence when determining the realizability of deferred tax assets. Projections of estimated future taxable income exclusive of reversing temporary differences are a source of positive evidence only when the projections are combined with a history of recent profitable operations and can be reasonably estimated. Otherwise, projections are considered inherently subjective and generally will not be sufficient to overcome negative evidence that includes cumulative losses in recent years. If necessary and available, tax planning strategies would be implemented to accelerate taxable amounts to utilize expiring carryforwards. These strategies would be a source of additional positive evidence supporting the realizability of deferred tax assets.

See Note 11 “Income Taxes” in Part II, Item 8 of this Annual Report for more information regarding our deferred taxes.

Changes in estimates and assumptions described in these critical accounting policies may result in material changes to our net income or loss from period to period.

New Accounting Pronouncements

For information regarding new accounting pronouncements, see the information in Note 1 “Organization and Summary of Significant Accounting Policies—New Accounting Pronouncements” in the consolidated financial statements in Part II, Item 8 of this Annual Report.

Item 7A.Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking 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 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. This forward-looking information provides indicators of how we view our ongoing market-risk exposure.

Interest Rate Risk

We are exposed to changes in interest rates which affect the interest earned on our interest-bearing deposits and the interest paid on borrowings under our Senior Credit Facility. Currently, we do not use interest rate derivative instruments to manage exposure to interest rate changes. At December 31, 2013, we had $130.0 million drawn under our Senior Credit Facility and we had $195.0 million outstanding at December 31, 2012. Borrowings under our Senior Credit Facility bear interest ranging from a base rate plus a margin of 0.75% to 1.75% on base rate borrowings and LIBOR plus a margin of 1.75% to 2.75% on LIBOR borrowings. The maturity date of the Senior Credit Facility is October 31, 2016.

At December 31, 2013, our total indebtedness outstanding also includes $497.4 million (net of unamortized initial purchasers’ discount of $12.6 million) related to our fixed rate 8.25% Senior Notes. At December 31, 2013, the estimated fair value of our 8.25% Senior Notes was approximately $546.3 million.

Commodity Price Risk

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and natural gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under our Senior Credit Facility is subject to periodic redetermination based in part on changing expectations of future prices. Lower prices may reduce the amount of oil and natural gas that we can economically produce. We currently sell all of our oil and natural gas production under price sensitive or market price contracts.

We use commodity derivative instruments to reduce our exposure to commodity price risks associated with future oil and natural gas production and not for trading purposes. The tables below provide information about our derivative instruments that were outstanding as of December 31, 2013. For a description of assumptions related to our calculations of fair value, please see Note 10, “Fair Value Measurements,” of the consolidated financial statements in Part II, Item 8 of this Annual Report.

Oil Contracts

	Fixed-Price Swaps Daily Average		Average	
Remaining Contract Term	Volume (Bbls)	Volume (Bbls)	Swap Price ($/Bbl)	Fair Value (In thousands)
January 2014 - December 2014	12,996	4,743,400	93.67	(28,816)
January 2015 - December 2015	1,500	547,500	97.70	(2,136)

Gas Contracts

	Fixed-Price Swaps Daily Average		Average	
Remaining Contract Term	Volume (Mmbtu)	Volume (Mmbtu)	Swap Price ($/Mmbtu)	Fair Value (In thousands)
January 2014 - December 2014	5,000	1,825,000	4.01	(319)
January 2015 - December 2015	4,300	1,569,500	4.31	238

The United States Congress 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. The new regulation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, required the Commodities Futures Trading

Commission (the “CFTC”) and the SEC to promulgate rules and regulations implementing the new legislation. In July 2012 certain definitions were adopted by the SEC and the CFTC and based on those definitions, we believe we will qualify for the end-user exception related to the clearing requirement for swaps, but we are required to adhere to new reporting and recordkeeping requirements.

Item 8.Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of EPL Oil & Gas, Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of changes in stockholders' equity and of cash flows present fairly, in all material respects, the financial position of EPL Oil & Gas, Inc. and its subsidiaries (the "Company") at December 31, 2013 and December 31, 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

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/s/ PricewaterhouseCoopers LLP

New Orleans, Louisiana

February 27, 2014

EPL OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

December 31, 2013 and 2012

(In thousands, except share data)

	December 31, 2013	2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 8,812	$ 1,521
Trade accounts receivable - net	70,707	67,991
Fair value of commodity derivative instruments	501	3,302
Deferred tax asset	8,949	3,322
Prepaid expenses	6,868	9,873
Total current assets	95,837	86,009
Property and equipment, at cost under the successful efforts method of accounting	2,355,219	2,025,647
Less accumulated depreciation, depletion, amortization and impairments	(618,788)	(427,580)
Net property and equipment	1,736,431	1,598,067
Deposit for Nexen Acquisition	7,040	-
Restricted cash	6,023	6,023
Fair value of commodity derivative instruments	238	211
Deferred financing costs - net of accumulated amortization of $5,549 and $2,596 at December 31, 2013 and 2012, respectively	10,106	12,386
Other assets	2,156	2,931
Total assets	$ 1,857,831	$ 1,705,627
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 59,431	$ 34,772
Accrued expenses	131,125	117,372
Asset retirement obligations	51,601	30,179
Fair value of commodity derivative instruments	29,636	10,026
Total current liabilities	271,793	192,349
Long-term debt	627,355	689,911
Asset retirement obligations	203,849	204,931
Deferred tax liabilities	122,812	67,694
Fair value of commodity derivative instruments	2,136	3,637
Other	673	1,132
Total liabilities	1,228,618	1,159,654
Commitments and contingencies (Note 13)		
Stockholders' equity:		
Preferred stock, par value $0.001 per share. Authorized 1,000,000 shares; no shares issued and outstanding at December 31, 2013 and 2012	-	-
Common stock, par value $0.001 per share. Authorized 75,000,000 shares; shares issued: 40,970,137 and 40,601,887 at December 31, 2013 and 2012, respectively; shares outstanding: 39,097,394 and 39,103,203 at December 31, 2013 and 2012, respectively	41	40

Additional paid-in capital	519,114	510,469
Treasury stock, at cost, 1,872,743 and 1,498,684 shares at December 31, 2013 and 2012, respectively	(31,157)	(20,477)
Retained earnings	141,215	55,941
Total stockholders’ equity	629,213	545,973
Total liabilities and stockholders' equity	$ 1,857,831	$ 1,705,627

See accompanying notes to consolidated financial statements.

EPL OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

For the Years Ended December 31, 2013, 2012 and 2011

(In thousands, except per share data)

	Year Ended December 31,		
	2013	2012	2011
Revenue:			
Oil and natural gas	$ 688,743	$ 422,529	$ 348,207
Other	4,295	1,104	120
Total revenue	693,038	423,633	348,327
Costs and expenses:			
Lease operating	165,841	94,850	70,281
Transportation	3,568	615	779
Exploration expenditures and dry hole costs	26,555	18,799	14,268
Impairments	2,937	8,883	32,466
Depreciation, depletion and amortization	200,359	113,581	104,624
Accretion of liability for asset retirement obligations	28,299	15,565	15,942
General and administrative	28,137	23,208	18,741
Taxes, other than on earnings	11,490	13,007	14,365
Gain on sales of assets	(28,681)	-	-
Other	34,942	4,678	9,735
Total costs and expenses	473,447	293,186	281,201
Income from operations	219,591	130,447	67,126
Other income (expense):			