ENERGY PARTNERS LTD
Form 10-K
March 08, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2011

or

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

For the transition period from to

Commission file number: 001-16179

Energy Partners, Ltd.

(Exact name of registrant as specified in its charter)

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

201 St. Charles Avenue, Suite 3400	
New Orleans, Louisiana	**70170**
(Address of principal executive offices)	**(Zip Code)**

504-569-1875

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 ¨ No x

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x 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 (§ 229.405 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 is not contained herein, and will not be contained, to the best of the 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	x
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 by 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.   Yes x   No ¨

The aggregate market value of the common stock held by non-affiliates of the registrant at June 30, 2011 (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 $426,053,651. As of February 24, 2012, there were 39,414,528 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 Energy Partners, Ltd. expected to be held on May 16, 2012

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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

Energy Partners, Ltd. (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 New Orleans, Louisiana and Houston, Texas. 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 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 operational strengths. As of December 31, 2011, we had estimated proved reserves of 37.1 million barrels of oil equivalent, or Mmboe, of which 74% were oil and 91% were proved developed. Of these proved developed reserves, 74% 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.

2011 Acquisitions

On February 14, 2011, we acquired 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) from Anglo-Suisse Offshore Partners, LLC (ASOP) 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 certain interests in producing oil and natural gas assets in the shallow-water central Gulf of Mexico shelf (the Main Pass Interests) from Stone Energy Offshore, LLC 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 million in aggregate principal amount of 8.25% senior notes due 2018 (the 8.25% Notes). After deducting the initial purchasers discount and estimated offering expenses, we realized net proceeds of approximately $202 million from the sale of the 8.25% Notes. We funded the Main Pass Acquisition with cash on hand.

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 predictable well control and production profiles. Our net proved reserves as of December 31, 2011 were 91% proved developed, which provides significant production visibility. Our fields offer significant development and exploration potential, with multiple producing zones and unexplored deeper horizons.

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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, 2011 were approximately 74% oil, and our net average daily production for the year ended December 31, 2011 was 73% 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.

Operating Control. We operate properties that contain approximately 74% 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 operate geographically focused properties located in the Gulf of Mexico shelf, which gives us the opportunity to minimize logistical costs and maximize the productivity of our field personnel. 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 2011 we acquired additional oil and gas properties within our area of focus. In addition to the extensive library we have over our legacy properties, we have licensed high quality multi-client 3-D data sets over recently acquired fields. We now have approximately 11,850 square miles of 3-D seismic data in the Gulf of Mexico. 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 thus aid in evaluation of drilling opportunities.

Experienced Management and Significant Technical Expertise. We have an experienced and technically-adept management team, averaging more than 20 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.

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 low-risk exploitation opportunities, as well as exploration prospects with multiple objectives and follow up opportunities. In 2011, we completed 27 workovers and ten drill wells, with an 84% success rate. Our fiscal year 2012 capital budget is $168 million, of which $110 million is allocated to development activities and $58 million to exploration projects within existing core field areas including seismic purchases. Additionally, we plan to spend approximately $27 million in 2012 on plugging, abandonment and other decommissioning activities. We will continue to focus on low-risk development projects, as well as a small number of high quality, high potential exploration prospects. We believe the properties we acquired in 2011 enhance our exploitation strategy to increase production from legacy fields and will provide us with substantial incremental exploration opportunities within those fields.

Build upon Regional Geologic Expertise. We are dedicating significant resources toward adding to our knowledge base of the geology underlying our core areas. We have budgeted capital to acquire additional 2-D and 3-D seismic data sets regionally across our current offshore operating areas and extending onshore Louisiana where the geology is characterized by the same productive horizons and structural features. Our geological and geophysical teams are analyzing well, paleontological and seismic data to identify exploration targets at intermediate and deeper depths as well as associated acquisition opportunities.

Target Acquisition Opportunities to Replace Reserves and Leverage Operational Strengths. As we did in 2011, 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. We intend to focus our acquisition strategy on operated Gulf of Mexico shelf and Gulf Coast assets that are characterized by production-weighted reserves, seismic coverage and operated positions, while allowing us to maintain a conservative capital structure. 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 visibility while reducing dry hole and exploration risk. We believe our expertise in the Gulf of Mexico and Gulf Coast region and in plugging and abandonment operations 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 have $200 million available under our $250 million credit facility we entered into concurrently with the

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consummation of the ASOP Acquisition in February 2011 (the credit facility). In order to maintain financial flexibility, we generally plan to fund our 2012 fiscal year exploration and development capital budget entirely with cash flow from operations. Additionally, our operational control enables us 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 credit facility and issuances of one or more 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 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 25% of the wellbores. With our core competency in plugging, abandonment and other decommissioning operations, 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, 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 providing such reports to the Securities and Exchange Commission (the SEC). In addition, our website contains our Corporate Governance Guidelines and the charters for our Audit, Compensation and Nominating and Governance 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, 2011, we had working interests in 25 producing fields located in the Gulf of Mexico shelf region, including larger legacy fields and smaller fields as follows:

- our East Bay producing field on the southern flank of the Mississippi River delta;
- three producing fields in the vicinity of the Bay Marchand salt dome (the Greater Bay Marchand area) and in close proximity to each other;
- two producing fields in our West Delta complex;
- two producing fields in our Main Pass complex; and
- 17 smaller producing fields offshore Louisiana.

Our East Bay field comprised approximately 27% of our production during the year ended December 31, 2011 and 39% of our proved reserves at December 31, 2011. It is comprised of 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 208 producing wells located along the coastline and in water depths ranging up to approximately 70 feet. We operate this field and own an average 96% working interest in our acreage position in this area. Our leasehold area covered 30,533 gross acres (29,426 net acres) as of December 31, 2011.

Our Greater Bay Marchand area comprised approximately 28% of our production during the year ended December 31, 2011 and 24% of our proved reserves at December 31, 2011. Our key assets in this area include the South Timbalier 26 and 41 fields and the Bay Marchand field located approximately 60 to 72 miles south of New Orleans in water depths of 73 feet or less. We own working interests ranging from 13% to 100% in the Greater Bay Marchand area. We operate the South Timbalier 26 and 41 blocks. During 2012, we plan to concentrate on exploitation opportunities in South Timbalier 26 and Bay Marchand with the benefit of newly-reprocessed seismic data.

Our West Delta complex comprised approximately 20% of our production during the year ended December 31, 2011 and 14% of our proved reserves at December 31, 2011. The West Delta complex, a legacy producing area, is located 62 miles south, southeast of New Orleans. It contains 23 producing wells in water depths ranging from 29 to 87 feet and is comprised of five lease blocks. We operate the West Delta complex and own an average 99% working interest in our acreage position in this area. During 2012, we plan to utilize our recently reprocessed 3-D seismic data to explore and exploit opportunities in this area.

Our Main Pass complex comprised approximately 6% of our production during the year ended December 31, 2011 and 13% of our proved reserves at December 31, 2011. The Main Pass complex is located 98 miles southeast of New Orleans. It contains 27 producing wells in water depths of approximately 250 feet and is comprised of two fields. We own a non-operated 50% working interest in most of our acreage position in this area. During 2012, we plan to evaluate certain well proposals in this area using our recently reprocessed 3-D seismic data.

The 17 smaller producing fields offshore Louisiana comprised approximately 14% of our production during the year ended December 31, 2011 and 9% of our proved reserves at December 31, 2011. These properties are located in water depths ranging from 18 to 300 feet with working interests ranging from 20% to 100%.

As of December 31, 2011, we also owned interests in 21 undeveloped blocks and one producing lease in the deepwater Gulf of Mexico. These deepwater Gulf of Mexico properties comprised approximately 5% of our production during the year ended December 31, 2011 and 1% of our proved reserves at December 31, 2011. Our working interests in our leases in this area ranged from 15% to 33%.

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, 2011, 2010 and 2009. Our estimates of proved reserves are based on reserve reports prepared as of December 31, 2011 by Netherland, Sewell & Associates, Inc. (NSAI) and Ryder Scott Company, LP (Ryder Scott), independent petroleum engineers. 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 prior twelve month period 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.

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	As of December 31, 2011	2010	2009
		(dollars in thousands)	
Total estimated net proved reserves:			
Oil (Mbbls)	27,301	17,223	19,923
Natural gas (Mmcf)	58,785	61,251	67,378
Total (Mboe)	37,099	27,431	31,153
Net proved developed reserves (1):			
Oil (Mbbls)	24,791	15,974	15,026
Natural gas (Mmcf)	52,739	56,410	57,139
Total (Mboe)	33,581	25,376	24,549
Net proved undeveloped reserves:			
Oil (Mbbls)	2,510	1,249	4,897
Natural gas (Mmcf)	6,046	4,841	10,239
Total (Mboe)	3,518	2,055	6,604
Estimated future net revenues before income taxes (2)	$ 1,555,059	$ 565,922	$ 534,771
Present value of estimated future net revenues before income taxes (PV-10) (2)(3)(5)	$ 1,100,701	$ 413,066	$ 395,997
Standardized measure of discounted future net cash flows (4)(5)	$ 876,169	$ 359,458	$ 393,802

(1) Net proved developed non-producing reserves as of December 31, 2011 (8,316 Mbbls and 33,604 Mmcf) were 13,917 Mboe, or 38% of our total proved reserves.

(2) Calculated using oil prices of $108.48, $77.85 and $57.70 per barrel, respectively, and natural gas prices of $4.16, $4.54 and $3.96 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.

(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.

We expect our proved undeveloped reserves (PUDs) as of December 31, 2011 of 3.5 Mmboe to begin converting from proved undeveloped to proved developed as the planned development projects begin in 2012. We project future development costs relating to the development of the PUDs remaining at December 31, 2011 to be approximately $44.0 million in 2012, $26.3 million in 2013, $0.2 million in 2014 and $2.4 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, 2011, our estimates of proved reserves are based on reserve reports prepared by the independent petroleum engineering firms NSAI and Ryder Scott, both nationally recognized engineering firms.

At December 31, 2011, estimates of 99% of our total estimated net proved reserves were prepared by NSAI, a nationally recognized engineering firm. NSAI provides a complete range of geological, geophysical, petrophysical and engineering services and has 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 intimately familiar with recognized industry reserves and resource definitions, specifically those set forth by the SEC. NSAI s letter is filed as an exhibit to this Annual Report on Form 10-K.

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 firms for evaluation and incorporation into our reserve estimates;

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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.

	$000,000	$000,000	$000,000
	Years Ended December 31,		
	2011	**2010**	**2009**
East Bay:			
Oil (Mbbls)	1,062	1,031	837
Natural gas (Mmcf)	76	78	295
Total (Mboe)	1,075	1,044	886
South Timbalier 26:			
Oil (Mbbls)	342	362	440
Natural gas (Mmcf)	1,203	1,167	1,394
Total (Mboe)	543	557	672

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.

	Years Ended December 31,		
	2011	**2010**	**2009**
	(In thousands)		
Acquisitions Proved (1)	$ 261,812	$	$
Acquisitions Unproved	14	623	85
Exploration	17,129	31,463	2,477
Development (2)	83,577	25,643	8,815
Costs incurred	$ 362,532	$ 57,729	$ 11,377

(1) Includes asset retirement obligations associated with acquiring the ASOP Properties and Main Pass Interests totaling $26.4 million during the year ended December 31, 2011.

(2) Includes asset retirement obligations incurred associated with finding, acquiring and developing our proved oil and natural gas reserves of $0.2 million and $0.1 million during the years ended December 31, 2011 and 2010, respectively. No asset retirement obligations were incurred associated with finding, acquiring and developing our proved oil and natural gas reserves during the year ended December 31, 2009.

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, 2011.

	Total Productive Wells	
	Gross	Net
Oil	264	232
Natural gas	50	36
Total	314	268

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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. Twenty-four gross oil wells and six 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.

Acreage

The following table sets forth information relating to acreage held by us as of December 31, 2011. Developed acreage is assigned to producing wells.

	Gross Acreage	Net Acreage
Developed:		
Gulf of Mexico Shelf	136,999	100,870
Deepwater Gulf of Mexico	5,760	1,600
Other	685	229
Total	143,444	102,699
Undeveloped:		
Gulf of Mexico Shelf	93,137	84,037
Deepwater Gulf of Mexico	97,920	25,983
Total	191,057	110,020

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. As of December 31, 2011, the net book value of the leases expiring in 2012 and 2013 is $0.1 million and $6.9 million, respectively. Leases covering 15% of our undeveloped net acreage expire in 2012, 59% expire in 2013, 8% expire in 2014, 5% expire in 2015, 8% expire in 2016 and 5% expire thereafter. We currently have no plans to develop leases expiring in 2012.

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. During the year ended December 31, 2011, we completed 27 gross (22.4 net) recompletion operations of which 23 gross (19.1 net) were successful; 5 gross (1.8 net) exploratory drilling operations of which 4 gross (1.3 net) were successful; and 5 gross (4.6 net) development wells of which 4 gross (3.6 net) were successful. We executed two gross (0.8 net) exploration wells late in 2011 which reached their target depths in January 2012 and were determined to be unsuccessful. During the year ended December 31, 2010, we completed 19 gross (16.2 net) recompletion operations of which 14 gross (11.2 net) were successful; 9 gross (6.4 net) exploratory drilling operations of which 7 gross (4.9 net) were successful; and 1 (gross and net) development well which was successful. Our 2009 development activities consisted of five gross (3.8 net) successful workovers. We executed one exploration well late in 2009 which was not completed until January 2010. We drilled no development or exploration wells that were completed in 2009.

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.

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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) 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.

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 Availability, Terms and Cost of Pipeline Transportation. 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 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. The ICA requires that we maintain a tariff on file with the FERC for this pipeline. The tariff sets forth the rate, which was established at a negotiated rate that has not been protested, as well as the rules and regulations governing this service. 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, upon completion of an investigation, the FERC finds that the existing rate is unlawful, it is authorized to require the carrier to refund the revenues in excess of the prior tariff collected during the pendency of the investigation and, in some cases, reparations for the two year period prior to the filing of a 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 apply to activities that relate only to non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities 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.

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FERC Market Transparency Rules. FERC s regulations require wholesale buyers and sellers of more than 2.2 million 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. While we believe that we are in substantial compliance with currently applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on us, the imposition of additional requirements in the future could materially adversely affect our operations and financial position.

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.

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 liability for response costs associated with releases of hazardous substances and damages to natural resources as a result of such releases, without

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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 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 Outer Continental Shelf Lands Act (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 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. We could be required to incur costs in the future for additional air pollution control equipment, 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 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 federal legislation, states and the EPA 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 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 are 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.

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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. 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 January 2011, we responded to a written request from BOEMRE 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 2013. This plan did not include the properties we acquired from ASOP. In December 2011, we submitted to the BSEE a plan related to the ASOP Properties for plugging, abandonment and decommissioning activities through 2014.

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 2011, ConocoPhillips accounted for approximately 51%, Chevron USA, Inc. accounted for approximately 17% and JP Morgan Ventures Energy accounted for approximately 12%. 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, 2011, we had 108 full-time employees, including 19 geoscientists, engineers and technicians and 48 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, particularly in the areas of drilling, completion, field, on-site 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.

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.

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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 reduced 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.

Chapter 11 Reorganization

See Management s Discussion and Analysis of Financial Condition and Results of Operations Year Ended December 31, 2010 Compared to Year Ended December 31, 2009 Chapter 11 Reorganization for a description and discussion of our Chapter 11 reorganization in 2009.

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 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 similar expressions.

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 credit facility;
- our substantial level of indebtedness;
- our ability to incur additional indebtedness;
- 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 promulgated by the BOEM and BSEE;
- the impact of political and regulatory developments;
- risks and liabilities associated with acquired properties or businesses;
- our ability to make and integrate acquisitions;
- oil and gas prices and competition; 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 credit facility, we intend to finance our development and exploration capital expenditures primarily through 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 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 credit facility. If we are unable to make scheduled payments on our credit facility, or if our financing requirements are not met by our 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.

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The borrowing base under our 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 credit facility is $200 million, and we currently have no amounts outstanding under our credit facility. Our borrowing base is subject to semi-annual and certain other interim re-determinations by our lenders in their sole discretion. The next re-determination of the borrowing base is scheduled to occur on May 1, 2012. The lenders will re-determine the borrowing base based on an engineering report with respect to our oil and natural gas reserves, which will take into account the prevailing oil and natural gas prices at such time. 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 credit facility.

In the future, we may not be able to access adequate funding under our 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 and natural gas commodity prices deteriorate, we anticipate that the revised borrowing base under our credit facility may be reduced. As a result, we may be unable to obtain adequate funding under our 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 credit facility exceed the re-determined borrowing base, we will be required to repay such excess within 60 days. We may not have the financial resources in the future to make any mandatory principal prepayments required under our 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% Notes (the guarantors), on a consolidated basis, have outstanding approximately $210 million of senior indebtedness, none of which is secured. 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% 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% 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% Notes (the Indenture) and our 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 existing debt levels, we may still be able to incur substantially more debt, 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 new and future credit facilities. As of December 31, 2011, we would have been able to incur approximately $909 million of additional indebtedness permitted by the Indenture, including approximately $200.0 million of debt under our credit facility, and other permitted debt categories or baskets. In addition, the Indenture will allow us to issue additional notes under certain circumstances, which will also be guaranteed by the guarantors. Although the terms of the 8.25% 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 credit facility and the 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 credit facility and the Indenture contain covenants that restrict our and our restricted subsidiaries or, in the case of the 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 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;
- issuing capital stock of certain subsidiaries;
- entering into sale/leaseback transactions;
- making acquisitions or investments; and

designating subsidiaries as unrestricted subsidiaries.

In addition, our credit facility restricts us from entering into certain hedging contracts or extending credit. Our 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 credit facility and the 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 credit facility, the 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 8.25% Notes and the terms of our other indebtedness outstanding at such time. If the amounts outstanding under our credit facility, the 8.25% 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.

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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.

Because our consolidated financial statements reflect fresh-start accounting adjustments made upon emergence from our Chapter 11 reorganization and because of the effects of the transactions that became effective pursuant to our plan of reorganization, financial information included in this Annual Report for periods prior to September 30, 2009 are not comparable with our financial information for periods on or after September 30, 2009.

In connection with our Chapter 11 reorganization, we adopted fresh-start accounting effective on September 30, 2009 in accordance with ASC Topic 852, Reorganizations. Our adoption of fresh-start accounting resulted in our becoming a new entity for financial reporting purposes. As required by fresh-start accounting, our assets and liabilities were adjusted to reflect fair value as of September 30, 2009. In addition to fresh-start accounting, our financial statements reflect the effects of all of the transactions implemented by our plan of reorganization. Accordingly, our financial statements for periods prior to September 30, 2009 are not comparable with our financial statements for periods on or after September 30, 2009. Furthermore, the estimates and assumptions used to implement fresh-start accounting are inherently subject to significant uncertainties and contingencies beyond our control. Accordingly, we cannot provide assurance that the estimates, assumptions, and values reflected in our valuations will be realized, and our actual results could vary materially.

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 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.

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Twenty-eight percent of our net daily production came from our South Timbalier and other Greater Bay Marchand area properties for the year ended December 31, 2011 and approximately 24% of our proved reserves at December 31, 2011 were located in the fields that comprise this area. In addition, 27% of our net daily production for the year ended December 31, 2011 came from our East Bay field and approximately 39% of our proved reserves at December 31, 2011 were located in this area. If the actual reserves associated with these two 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, 2011, our independent petroleum engineers estimate that, on average, 62% 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.

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, 2011, we operated approximately 74% of our properties, based on proved reserves at December 31, 2011. 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 a combination of crude oil swap and collar 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. 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 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.

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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 s 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 a buyer 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.

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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 natural gas and oil 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 and related PV-10 as of December 31, 2011 and 2010 and standardized measure of discounted future net cash flows as of December 31, 2011, 2010 and 2009, all of which have been prepared and presented under new SEC rules. These new rules are 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 for any periods ending on or after December 31, 2009 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, 2011 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, 2011, approximately 9% of our total proved reserves were undeveloped, and approximately 38% 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 and production may lower the threshold of economic recoverability. Though our 2012 fiscal year capital budget contemplates the deployment of a significantly larger amount of capital compared to the capital expenditures in 2011, 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.

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Currently, we have general liability insurance coverage with an annual aggregate limit of $2.0 million and umbrella liability coverage with an aggregate limit of $150.0 million applicable to our working interest. Our general liability policy is subject to a $25,000 per incident deductible. We also have an offshore property physical damage policy that contains a $90.0 million annual aggregate named windstorm limit of which we self-insure approximately 9%. This offshore property physical damage policy is subject to a $2.5 million deductible that applies to non-named windstorm occurrences and a $20.0 million deductible that applies to named windstorm events. Further, there are sub-limits within the named windstorm annual aggregate limit for re-drill, plugging and abandonment and removal of wreck that range from $10.0 million to $45.0 million. Our operational control of well coverage provides limits that vary by well location and depth and range from a combined single limit of $20.0 million to $75.0 million per occurrence. Deepwater wells have a coverage limit of $50.0 million per occurrence. Additionally, we maintain $150.0 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, which limit is 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 severely 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 severely impact our financial position. For example, we experienced production interruptions in 2005, 2006 and 2007 from Hurricanes Katrina and Rita and in 2008 and 2009 from Hurricanes Gustav and Ike for which we had no production interruption insurance.

We reevaluate the purchase of insurance, policy limits and terms annually each April. 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. CGA has chartered its marine equipment to the Marine Spill Response Corporation (MSRC), a private, not-for-profit marine spill response organization which is funded by the Marine Preservation Association (MPA), a member-supported, not-for-profit organization created to assist the petroleum and energy-related industries by addressing problems caused by oil spills on water. MSRC owns and operates a fleet of dedicated Oil Spill Response Vessels (OSRV), ocean-going barges, shallow water skimming systems, other response equipment and enhanced communications capabilities in various regions including the Gulf of Mexico. MSRC maintains CGA s equipment in various warehouse locations (currently including, according to CGA s website, 14 skimming vessels with capacities ranging from 3,000 to 43,000 barrels per day, 17 skimmers with capacities up to 3,770 barrels per day, numerous containment and storage systems including thousands of feet of boom and two fire boom systems, tanks and storage barges, wildlife cleaning and rehabilitation facilities, both aerial and vessel dispersant spray systems and more than 33,300 gallons of dispersant) at staging points around the Gulf of Mexico in its ready state. In the event of a spill, MSRC 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 MSRC. MSRC has oil spill response equipment independent of, and in addition to, CGA s equipment. MSRC s capabilities are augmented by a network of over 100 participants in the Spill Team Area Responders (STARs) program, an affiliation of environmental response contractors located at over 200 locations throughout the country. MSRC s equipment currently includes, according to MSRC s website, 15 oil spill response vessels with temporary storage for 4,000 barrels of oil and the ability to separate oil and water; 19 oil spill response barges with storage capacities between 12,000 and 68,000

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barrels; 68 shallow water barges; 600,000 feet of boom; over 240 skimming systems; six self-propelled skimming vessels; seven mobile communication suites comprising telephone and computer connections and marine, aviation and business band radios; various small crafts and shallow water vessels; two dispersant aircraft; and four dispersant/spotter aircraft. In the event of a spill, MSRC 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 and 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.

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 be required to either purchase relatively expensive put options, or commit to deliver future production, 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 make cash deposits available to counterparties as they mark to market these financial hedges. Proposed changes in regulations affecting derivatives may further limit or raise the cost, or increase the credit support required to hedge. 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 that may arise 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. 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 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. 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 any such changes in current laws and regulations will occur.

We do not know how the recent reorganization of the former BOEMRE will 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 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 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. 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.

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.

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 pending 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 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. Several of the EPA s greenhouse gas rules are being challenged in pending court proceedings and, depending on the outcome of such proceedings, such rules may be modified or rescinded 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.

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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.

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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 adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.

The U.S. Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The new legislation was signed into law by the President on July 21, 2010, and requires the CFTC and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation 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 legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material effect on our financial condition and our results of operations.

The proposed U.S. federal budget for fiscal year 2012 includes certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

The 2012 fiscal budget proposed by the Obama administration would repeal many tax incentives and deductions that are currently used by U.S. oil and gas companies and impose new taxes. The provisions include without limitation: the elimination of current deductions for intangible drilling and development costs; the repeal of the percentage depletion allowance for oil and gas properties; an extension of the amortization period for certain geological and geophysical expenditures; and the elimination of the deduction for certain U.S. production activities.

To date, none of these proposals has been enacted. However, should any of these proposals be enacted, our taxes may increase, potentially significantly, which would have a negative impact on our cash flows. This could also reduce our drilling activities. Since none of these proposals has yet been voted on or become law, we do not know the ultimate impact any of these proposals may have on our business.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

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

Item 3. ***Legal Proceedings***

For information regarding legal proceedings, see the information in Note 13, Commitments and Contingencies in the consolidated financial statements in Part II, Item 8 of this Annual Report.

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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 ($)	Low ($)
2010		
First Quarter	12.35	8.28
Second Quarter	14.62	11.36
Third Quarter	13.22	9.61
Fourth Quarter	15.00	10.75
2011		
First Quarter	18.21	13.79
Second Quarter	18.56	13.69
Third Quarter	18.08	10.36
Fourth Quarter	16.05	9.99
2012		
First Quarter (through February 24, 2012)	18.04	14.72

On February 24, 2012, the last reported sales price of our common stock on the NYSE was $17.63 per share.

As of February 24, 2012, there were approximately 160 holders of record of our common stock.

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 credit facility and the Indenture related to our 8.25% 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.

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2011 with respect to compensation plans under which our equity securities are authorized for issuance.

	Number of 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
Equity compensation plans approved by stockholders			
Equity compensation plans not approved by stockholders (3)	1,119,746	$ 13.05	1,201,707

Total	1,119,746	$ 13.05	1,201,707

(1) Comprised of 934,013 shares subject to issuance upon the exercise of options and 185,733 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) The form of the 2009 Long Term Incentive Plan was filed with the Plan Supplement and approved by the Bankruptcy Court prior to our emergence from Chapter 11 reorganization. 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 significant features of the above plan.

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Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (1)	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs (1) (in thousands)
December 2011	429,000	$ 13.53	429,000	$ 7,188

(1) On August 29, 2011, we announced that the Board of Directors authorized a program for the repurchase of shares of our outstanding common stock for up to an aggregate cash purchase price of $20.0 million. We are funding the stock repurchases out of cash on hand. The repurchased shares will be accumulated and held in treasury. The repurchases are 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.

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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 graph below compares our cumulative five-year total shareholder return on common stock with the cumulative returns of the Russell 2000 Index and the customized peer group described below. The graph tracks the performance of a $100 investment in our common stock, in the customized peer group, and the index (with the reinvestment of all dividends) from December 31, 2006 to December 31, 2011. This historic price performance is not necessarily indicative of future stock performance.

	12/06	12/07	12/08	12/09	12/10	12/11
Energy Partners Ltd.	**100.00**	**48.36**	**5.53**	**35.01**	**60.85**	**59.79**
Russell 2000	**100.00**	**98.43**	**65.18**	**82.89**	**105.14**	**100.75**
2011 Peer Group	**100.00**	**112.33**	**37.41**	**46.73**	**73.46**	**74.17**

Our peer group includes: ATP Oil & Gas Corporation, Energy XXI (Bermuda) Limited, McMoran Exploration Company, Stone Energy Corporation and W & T Offshore, Inc.

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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, 2011	Year Ended December 31, 2010	Period from October 1, 2009 through December 31, 2009	Period from January 1, 2009 through September 30, 2009	Years Ended December 31, 2008	2007 (2)
	(In thousands, except per share data)					
Statement of Operations Data:						
Revenue	$ 348,327	$ 239,909	$ 56,750	$ 134,885	$ 356,252	$ 454,649
Income (loss) from operations (3)	67,126	7,309	(4,523)	(51,323)	(25,531)	(56,013)
Net income (loss)	26,611	(8,468)	(21,012)	(36,114)	(52,212)	(79,955)
Basic income (loss) per common share	$ 0.66	$ (0.21)	$ (0.53)	$ (1.12)	$ (1.63)	$ (2.32)
Diluted income (loss) per common share	$ 0.66	$ (0.21)	$ (0.53)	$ (1.12)	$ (1.63)	$ (2.32)

	Successor Company As of December 31,			Predecessor Company (1) As of December 31,	
	2011	2010	2009	2008	2007 (2)
	(In thousands)				
Balance Sheet Data:					
Total assets (4)	$ 915,220	$ 626,906	$ 709,228	$ 766,766	$ 814,856
Long-term debt, excluding current maturities(4) (5)	204,390		58,590		484,501
Stockholders equity	491,045	473,116	480,087	57,119	101,970
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. See Note 17, Reorganization and Fresh-Start Accounting of the consolidated financial statements in Part II, Item 8 of this Annual Report for further information.

(2) Amounts in 2007 reflect the sale of substantially all of our onshore South Louisiana assets in June 2007.

(3) The loss from operations in 2008 and 2007 includes business interruption insurance recoveries of $4.2 million and $9.1 million, respectively, from deferred production at our covered fields resulting from Hurricanes Gustav and Ike in 2008 and Katrina and Rita in 2005.

(4) During the year ended December 31, 2011, we acquired the ASOP Properties and Main Pass Interests. In connection with the ASOP Acquisition, we issued the 8.25% Notes.

(5) At December 31, 2011 and 2007, none of our debt was classified as current. At December 31, 2010, we had no borrowings outstanding. At December 31, 2009 and 2008, long-term debt classified as current was $18.8 million and $497.5 million, respectively.

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, 2011, we had estimated proved reserves of 37.1 million barrels of oil equivalent, or Mmboe, of which 74% were oil and 91% were proved developed. Of these proved developed reserves, 74% were oil reserves.

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2011 Acquisitions

On February 14, 2011, we acquired 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) from Anglo-Suisse Offshore Partners, LLC (ASOP) 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 certain interests in producing oil and natural gas assets in the shallow-water central Gulf of Mexico shelf (the Main Pass Interests) from Stone Energy Offshore, L.L.C. 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 ASOP Properties include the West Delta complex, the Main Pass complex and the South Pass complex which are described in Part 1, Item 1, Business Properties. 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 million in aggregate principal amount of 8.25% senior notes due 2018 (the 8.25% Notes) offered to qualified institutional buyers pursuant to Rule 144A promulgated under the Securities Act of 1933, as amended (the Securities Act), and to persons outside the United States pursuant to Regulation S promulgated under the Securities Act. After deducting the initial purchasers discount and offering expenses, we realized net proceeds of approximately $202 million. On July 14, 2011, we and our guarantor subsidiaries (the Guarantors) filed a registration statement with the SEC, which was declared effective on July 26, 2011, offering to exchange a new series of freely tradable notes having substantially identical terms as the 8.25% Notes (Exchange Notes) for the 8.25% Notes. Pursuant to this offering, 100% in aggregate principal amount of the 8.25% Notes was exchanged for the Exchange Notes, effective as of August 29, 2011. On February 14, 2011, we also entered into an agreement for a credit facility. We funded the Main Pass Acquisition with cash on hand. See Financial Condition, Liquidity and Capital Resources for more information regarding the 8.25% Notes and the credit facility.

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 ASOP 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 2011, we spent approximately $101 million on development and exploration activities, $84 million on our development efforts and $17 million on exploration projects. During 2011, we focused our development efforts on our Gulf of Mexico shelf asset base, primarily our oil-rich East Bay field as well as the Greater Bay Marchand and West Delta areas. We also spent approximately $32 million on plugging, abandonment and other decommissioning activities during 2011. Our fiscal year 2012 capital budget is $168 million, of which $110 million is allocated to development activities and $58 million to exploration projects within existing core field areas including seismic purchases. Additionally, we plan to spend approximately $27 million in 2012 on plugging, abandonment and other decommissioning activities.

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, which has resulted in the maintenance of our upward trend in oil production volumes and the decline in our natural gas volumes.

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 Gulf of Mexico shelf assets that are characterized by production-weighted reserves, seismic coverage and operated positions. 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.

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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. Generally, we fund any exploration and development expenditures with internally generated cash flows.

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

We are also focused on the development of a core competency in plugging, abandonment and decommissioning operations, which 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 LOE associated with maintaining idle infrastructure.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Results of Operations

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

	Year Ended December 31, 2011	2010
Net production (per day):		
Oil (Bbls)	8,089	6,401
Natural gas (Mcf)	17,968	42,488
Total (Boe)	11,084	13,482
Average sales prices:		
Oil (per Bbl)	$ 108.81	$ 72.80
Natural gas (per Mcf)	4.11	4.49
Total (per Boe)	$ 86.07	$ 48.72
Oil & natural gas revenues (in thousands):		
Oil	$ 321,275	$ 170,079
Natural gas	26,932	69,691
Total	$ 348,207	$ 239,770
Impact of derivatives settled during the period (1):		
Oil (per Bbl)	$ (5.87)	$ (3.62)
Natural gas (per Mcf)	$	$ 0.01
Average costs (per Boe):		
LOE	$ 17.37	$ 10.64
Depreciation, depletion and amortization (DD&A)	$ 25.86	$ 21.25
Accretion of liability for asset retirement obligations	$ 3.94	$ 2.61
Taxes, other than on earnings	$ 3.55	$ 2.06
G&A expenses	$ 4.63	$ 3.67
Increase (decrease) in oil and natural gas revenue due to:		
Change in prices of oil	$ 84,146	
Change in production volumes of oil	67,050	
Total increase (decrease) in oil sales	151,196	
Change in prices of natural gas	(5,904)	
Change in production volumes of natural gas	(36,855)	
Total decrease in natural gas sales	(42,759)	

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

Overview

During the year ended December 31, 2011, we completed five (5) development drilling operations, four (4) of which were successful; twenty-seven (27) recompletion operations, twenty-three (23) of which were successful; and five (5) exploratory drilling operations, four (4) of which were successful. As of December 31, 2011, we were drilling two (2) additional exploratory wells which reached their target depths in January 2012 and were determined to be unsuccessful.

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Our operating results for the year ended December 31, 2011, compared to the year ended December 31, 2010, reflect significantly higher average selling prices for our oil partially offset by lower average selling prices for our natural gas. The product mix for our production for the year ended December 31, 2011 was 73% oil (including natural gas liquids), compared to 47% oil (including natural gas liquids) for the comparable period in 2010. This change in product mix results from declines in production of natural gas and natural gas liquids, partially offset by an increase in oil production. Additionally, our results include production from the ASOP Properties and Main Pass Interests, which were acquired during 2011, of 3,283 Boe per day for the year ended December 31, 2011.

For the year ended December 31, 2011, our revenues increased 45% as compared to the year ended December 31, 2010, due primarily to the higher oil sales prices and the increase in oil production. Our overall production volumes, including barrel of oil equivalent natural gas volumes, decreased by 18% for the year ended December 31, 2011 when compared to the year ended December 31, 2010. Our Gulf of Mexico shelf production decreased 13% in the year ended December 31, 2011, as compared to the year ended December 31, 2010, due primarily to production declines in our predominantly natural gas fields, partially offset by production from the ASOP Properties. In addition, our deepwater production, primarily natural gas, declined 58% for the year ended December 31, 2011, as compared to the year ended December 31, 2010, due to natural reservoir decline from our deepwater well and curtailed production for extended periods during the third and fourth quarters of 2011, and continuing through the first quarter of 2012, due to third party downstream facility modifications.

Our effective income tax rate for the year ended December 31, 2011 was 35.8%. The income tax expense (all of which is 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. Our effective income tax rate for the year ended December 31, 2010 was 34.2%. The income tax benefit recorded on the net loss for the year ended December 31, 2010 was reduced due to our applying the change in our estimated effective income tax rate for the full year 2010, from 36% to 37.6%, to our net deferred tax liabilities. The change in our estimated effective income tax rate for 2010 was primarily related to state income taxes.

Revenue and Net Income (Loss)

	Year Ended December 31, 2011	Year Ended December 31, 2010		
		(in thousands)	$ Change	% Change
Oil and natural gas revenues	$ 348,207	$ 239,770	$ 108,437	45%
Net income (loss)	26,611	(8,468)	34,432	NM

NM Not Meaningful

Our oil and natural gas revenues increased primarily due to a 49% increase in average selling prices for our oil and a 26% increase in oil production in the year ended December 31, 2011 as compared to the year ended December 31, 2010, offset in part by a 58% decline in natural gas production and a 8% decline in average selling prices for our natural gas in the year ended December 31, 2011 as compared to the year ended December 31, 2010. Oil represented 73% of total production for the year ended December 31, 2011, as compared to 47% of total production for the year ended December 31, 2010.

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Operating Expenses

Our operating expenses primarily consisted of the following:

	Year Ended December 31, 2011	2010 (in thousands)	$ Change	% Change
LOE	$ 70,281	$ 52,365	$ 17,916	34%
Exploration expenditures and dry hole costs	14,268	6,441	7,827	122%
Impairments	32,466	26,142	6,324	24%
DD&A, including accretion expense	120,566	117,406	3,160	3%
G&A expenses	18,741	18,078	663	4%
Taxes, other than on earnings	14,365	10,133	4,232	42%

LOE has increased primarily due to the addition of the ASOP Properties in 2011. The increase in our LOE per Boe is due to the increase in our oil production, which generally has a higher per Boe cost to produce than natural gas, and a decrease in natural gas production and total Boe production.

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. As of December 31, 2011, we were drilling two additional exploratory wells which reached their target depths in January 2012 and were determined to be unsuccessful. We expect costs in the first quarter of 2012 to total approximately $1.8 million related to these dry holes. In addition, the expense in the year ended December 31, 2011 includes $0.8 million of seismic expenditures and delay rentals. In the year ended December 31, 2010, we completed drilling two exploratory dry holes and recorded approximately $5.1 million of dry hole costs. In addition, the expense in the year ended December 31, 2010 includes $1.3 million of seismic expenditures and delay rentals. 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, 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. Impairments for the year ended December 31, 2010 were primarily related to the decline in our estimate of future natural gas prices as of September 30, 2010 as compared to June 30, 2010 affecting two producing fields, including our deepwater producing well, and to reservoir performance of one of these fields and one additional producing field. 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. Due to our reorganization and application of fresh-start accounting, we recorded our oil and natural gas properties in the consolidated balance sheet of the Successor Company at their estimated fair market values, based on assumptions including the estimates of future oil and natural gas prices as of September 30, 2009. In addition, our 2011 acquisitions were recorded at fair value using oil and natural gas prices in February and November of 2011. As a result, our capitalized oil and natural gas property costs may be more sensitive to future material impairments than those of other companies in our industry.

DD&A per Boe increased primarily due to the acquisition of the ASOP Properties and the Main Pass Interests which have higher per Boe DD&A rates because they were recorded at estimated fair values at their respective 2011 acquisition dates.

G&A expenses increased in the year ended December 31, 2011, as compared to the year ended December 31, 2010, primarily as a result of an increase in non-cash share-based compensation and costs incurred in our acquisition efforts, partially offset by decreases in employee related costs. Non-cash share-based compensation was $2.5 million and $1.3 million in the years ended December 31, 2011 and 2010, respectively. Acquisition costs related to the ASOP Acquisition and Main Pass Acquisition totaled approximately $0.6 million in the year ended December 31, 2011.

Taxes, other than on earnings, increased in the year ended December 31, 2011 as compared to the year ended December 31, 2010, due primarily to higher average sales prices for oil (for which production taxes are based on selling price).

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Other Income and Expense

Interest expense increased in the year ended December 31, 2011, as compared to the year ended December 31, 2010. For the year ended December 31, 2011, our interest expense consists primarily of interest on our 8.25% Notes issued on February 14, 2011 in connection with the ASOP Acquisition. For the year ended December 31, 2010, interest expense consisted primarily of interest expense on our 20% Senior Subordinated Secured PIK Notes due 2014 (the PIK Notes) and the term portion of our previous credit facility, which were outstanding during that period. We redeemed all of our outstanding PIK Notes on June 28, 2010.

Other income (expense) in the year ended December 31, 2011 includes a net loss of $5.9 million consisting of an unrealized 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 our oil fixed-price swaps. Other income (expense) in the year ended December 31, 2010 includes a net loss of $4.9 million consisting of an unrealized gain of $3.5 million due to the change in fair market value of derivative instruments and a loss of $8.4 million on derivative instruments settled during the period primarily from the impact of our oil fixed-price swaps.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Basis of Presentation

On May 1, 2009, we and certain of our subsidiaries filed voluntary petitions (In re: Energy Partners, Ltd., et. al., Case No. 09-32957) for reorganization under Chapter 11 of Title 11 of the United States Code, 11 U.S.C. §§ 101 et seq., as amended (Chapter 11), in the United States Bankruptcy Court for the Southern District of Texas, Houston Division (the Bankruptcy Court). On September 17, 2009, the Bankruptcy Court entered an order confirming the plan of reorganization we had filed with the Bankruptcy Court (the Plan of Reorganization). On September 21, 2009 (the Exit Date), we emerged from Chapter 11 reorganization pursuant to the Plan of Reorganization. In accordance with ASC Topic 852, Reorganizations (ASC 852), 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. In this Annual Report, references to the Predecessor Company refer to reporting dates of the Company through September 30, 2009, including the effect of the provisions of the Plan of Reorganization and the application of fresh-start accounting; activity of the Company subsequent to September 30, 2009 is referred to as that of the Successor Company. For more information on our reorganization, see Chapter 11 Reorganization.

As a result of our reorganization under Chapter 11 and the application of fresh-start accounting in accordance with ASC 852, our financial statements for periods prior to September 30, 2009 are not comparable to our financial statements for periods on or after September 30, 2009. The presentation of combined financial information for the year ended December 31, 2009 is not in accordance with accounting principles generally accepted in the United States (GAAP). However, our Chapter 11 reorganization did not result in the disposition of any of our oil and natural gas properties. As a result, the comparability of certain components of our operating results and key operating performance measures, specifically those related to production, average oil and natural gas selling prices, revenues and lease operating expenses, was not significantly impacted by the reorganization. Therefore, we believe that for purposes of discussion and analysis, those combined financial results are useful for management and investors when analyzing our operational performance. In the following discussion, references to combined results for the year ended December 31, 2009 combine the period from January 1, 2009 through September 30, 2009 (reflecting the operations of the Predecessor Company) with the period from October 1, 2009 through December 31, 2009 (reflecting the operations of the Successor Company).

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Results of Operations

The following table presents information about our oil and natural gas operations. Our Chapter 11 reorganization did not result in the disposition of any of our oil and natural gas properties. As a result, the comparability of certain components of our operating results and key operating performance measures, specifically those related to production, average oil and natural gas selling prices, revenues and lease operating expenses, was not significantly impacted by the reorganization.

	Successor Company Year Ended December 31, 2010	Successor Company Period from October 1, 2009 through December 31, 2009	Predecessor Company Period from January 1, 2009 through September 30, 2009	Non-GAAP Combined Results for the Year Ended December 31, 2009
Net production (per day):				
Oil (Bbls)	6,401	6,091	5,127	5,370
Natural gas (Mcf)	42,488	45,726	61,029	57,172
Total (Boe)	13,482	13,712	15,299	14,899
Average sales prices:				
Oil (per Bbl)	$ 72.80	$ 68.03	$ 49.88	$ 55.07
Natural gas (per Mcf)	4.49	4.42	3.89	3.99
Total (per Boe)	$ 48.72	$ 44.95	$ 32.22	$ 35.18
Oil & natural gas revenues (in thousands):				
Oil	$ 170,079	$ 38,121	$ 69,812	$ 107,933
Natural gas	69,691	18,587	64,771	83,358
Total	$ 239,770	$ 56,708	$ 134,583	$ 191,291
Impact of derivatives settled during the period (1):				
Oil (per Bbl)	$ (3.62)	$ (1.73)	$ 1.82	$ 0.80
Natural gas (per Mcf)	$ 0.01	$	$ 0.01	$ 0.01
Average costs (per Boe):				
LOE	$ 10.64	$ 10.63	$ 11.09	$ 10.98
Taxes, other than on earnings	$ 2.06	$ 1.65	$ 1.43	$ 1.48
G&A expenses	$ 3.67	$ 3.60	$ 4.67	$ 4.42
Increase (decrease) in oil and natural gas revenue due to:				
Change in prices of oil	$ 34,751			
Change in production volumes of oil	27,395			
Total increase (decrease) in oil sales	62,146			
Change in prices of natural gas	10,461			
Change in production volumes of natural gas	(24,128)			
Total decrease in natural gas sales	(13,667)			

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

Overview

During the year ended December 31, 2010, we completed nineteen (19) recompletion operations, fourteen (14) of which were successful; nine (9) exploratory drilling operations, seven (7) of which were successful; and one (1) development well which was successful.

Our operating results for the year ended December 31, 2010, compared to the year ended December 31, 2009, reflect higher average selling prices for both our oil and natural gas and declines in LOE and G&A expenses. The decline in LOE and G&A expenses was primarily due to the impact of our cost reduction efforts in the 2010 period.

For the year ended December 31, 2010, our revenues increased 25% as compared to the year ended December 31, 2009 due primarily to higher average selling prices for our oil production and the increase in oil production. Our overall production volumes declined by 10%, on a barrel equivalent basis, for the year ended December 31, 2010 when compared to the year ended December 31, 2009. Additionally, our product mix reflects an increase in oil production and a decrease in natural gas production for the year ended December 31, 2010 as compared to the year ended December 31, 2009.

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Our Gulf of Mexico shelf production declined 8% in the year ended December 31, 2010, as compared to the year ended December 31, 2009, due primarily to natural reservoir declines in the second half of 2009 and continuing throughout 2010, offset in part by an overall increase in oil production primarily from our East Bay field. Our deepwater production, primarily natural gas, declined 18% for the year ended December 31, 2010, as compared to the year ended December 31, 2009, which was due primarily to natural reservoir decline from our deepwater well. We expect that our deepwater production will continue to decline in the future.

In June 2010, we paid a total of $70.9 million of principal and accrued interest in connection with the redemption of the PIK Notes, which had been issued in connection with the Plan of Reorganization. We redeemed all of the PIK Notes at 100% of the outstanding aggregate principal amount, plus accrued and unpaid interest. As a result, during the year ended December 31, 2010, we recorded a loss on extinguishment of debt totaling $5.6 million which represents the total of the unamortized original issue discount and unamortized deferred financing costs associated with the PIK Notes.

Our effective income tax rate for the year ended December 31, 2010 was 34.2%. The income tax benefit recorded on the net loss for the year ended December 31, 2010 was reduced due to our applying the change in our estimated effective income tax rate for the full 2010 year, from 36.0% to 37.6%, to our net deferred tax liabilities. The change in our estimated effective income tax rate for 2010 was primarily related to state income taxes. Our effective income tax rate for the quarter ended December 31, 2009 was an approximately 35% benefit on the loss before income taxes for the quarter as a result of the change in our deferred tax position due to the reorganization. Our effective income tax rate for the nine months ended September 30, 2009 was zero because we provided a valuation allowance against the net deferred tax assets generated during the nine months ended September 30, 2009. The impact of the reorganization on our deferred tax position is more fully addressed in Note 11, Income Taxes, of the consolidated financial statements in Part II, Item 8 of this Annual Report.

Revenues

	Successor Company Year Ended December 31, 2010	Successor Company Period from October 1 through December 31, 2009	Predecessor Company Period from January 1 through September 30, 2009	Non-GAAP Combined Year Ended December 31, 2009
	(in thousands)			
Oil and natural gas revenues	$ 239,770	$ 56,708	$ 134,583	$ 191,291

Our oil and natural gas revenues increased primarily due to a 32% increase in average selling prices for our oil and a 19% increase in oil production in the year ended December 31, 2010 as compared to the year ended December 31, 2009, offset in part by a 26% decline in natural gas production in the year ended December 31, 2010 as compared to the year ended December 31, 2009. The percentage of production represented by oil has increased for us. Oil represented 47% of total production for the year ended December 31, 2010, as compared to 36% of total production for the year ended December 31, 2009.

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Operating Expenses

Our operating expenses primarily consist of the following:

	Successor Company Year Ended December 31, 2010	Successor Company Period from October 1 through December 31, 2009	Predecessor Company Period from January 1 through September 30, 2009	Non-GAAP Combined Year Ended December 31, 2009
	(in thousands)			
LOE	$ 52,365	$ 13,410	$ 46,296	$ 59,706
Exploration expenditures and dry hole costs	6,441	453	1,650	2,103
Impairments	26,142	8,514	8,082	16,596
DD&A, including accretion expense (1)	117,406	31,472	101,480	NM
G&A expenses	18,078	4,537	19,493	24,030
Taxes, other than on earnings	10,133	2,083	5,987	8,070

NM Not meaningful.

(1) DD&A, including accretion expense, is not comparable for the periods presented due to the application of fresh-start accounting.

We completed drilling two exploratory dry holes and recorded approximately $5.1 million of dry hole costs in the year ended December 31, 2010. In addition, the expense in the year ended December 31, 2010 includes $1.3 million of seismic expenditures and delay rentals.

Impairments for the year ended December 31, 2010 were primarily related to the decline in our estimate of future natural gas prices as of September 30, 2010 as compared to June 30, 2010 affecting two producing fields, including our deepwater producing well, and to reservoir performance of one of these fields and one additional producing field. These producing 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 during the year ended December 31, 2010. Impairments recorded by the Successor Company in the quarter ended December 31, 2009 were primarily related to two wells in our Gulf of Mexico shelf area, one of which was unsuccessfully recompleted in 2010; the other was determined to be mechanically unable to produce a behind-pipe reservoir. Impairments recorded by the Predecessor Company in the period from January 1, 2009 through September 30, 2009 were primarily due to amounts recorded in the quarter ended March 31, 2009 related to two producing fields which were determined to have future net cash flows less than their carrying values due to commodity price declines and reservoir performance.

Our DD&A was affected by our reorganization and application of fresh-start accounting. Thus, changes in DD&A and DD&A rates are not comparable for the periods presented. Generally, because oil prices were higher as of September 30, 2009, the date at which we applied fresh-start accounting, as compared to oil prices as of December 31, 2008, a date at which we recorded significant impairments of certain of our oil and natural gas properties, estimated reorganization values allocated to our longer-lived oil properties were higher on a per Boe basis than values allocated to our shorter-lived natural gas properties. As a result, our overall DD&A rate per Boe declined for the 2010 period.

Our reported asset retirement obligations were impacted by our reorganization and application of fresh-start accounting. We estimate our asset retirement obligations based on factors described in Discussion of Critical Accounting Policies. The accretion of liability for asset retirement obligations is significantly affected by the credit-adjusted risk-free discount rate applied to our estimated future costs to plug, abandon and perform other decommissioning activities on our oil and natural gas properties. As a result of our reorganization, the credit adjusted risk-free rate we used as of September 30, 2009 was significantly higher than the rates used to record asset retirement obligations in prior periods.

G&A expenses, which include cash and non-cash share-based compensation of $1.3 million and $4.3 million in the years ended December 31, 2010 and 2009, respectively, decreased in the year ended December 31, 2010, as compared to the year ended December 31, 2009, primarily as a result of the impact of cost reduction efforts on the 2010 period, offset in part by litigation costs and costs incurred in our acquisition efforts in the 2010 period.

Taxes, other than on earnings, increased in the year ended December 31, 2010 as compared to the year ended December 31, 2009, due primarily to production taxes resulting from higher average sales prices for oil (for which production taxes are based on selling price) and higher estimated franchise taxes in the 2010 period.

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Other Income and Expense

Our interest expense was impacted by our Chapter 11 reorganization and is not comparable for the periods presented. Interest expense in the year ended December 31, 2010 consists primarily of interest expense on our PIK Notes and our prior credit facility, which had been entered in connection with the Plan of Reorganization. We redeemed all of our outstanding PIK Notes on June 28, 2010. Interest expense in the nine months ended September 30, 2009 consists primarily of interest expense on the Predecessor Company Notes (defined below in Chapter 11 Reorganization). However, we had discontinued accruing interest on the Predecessor Company Notes as of May 1, 2009, the date we filed for reorganization under Chapter 11, and the Predecessor Company Notes were discharged in the reorganization.

Other income (expense) in the year ended December 31, 2010 includes a net loss of $4.9 million consisting of an unrealized gain of $3.5 million due to the change in fair market value of derivative instruments and a loss of $8.4 million on derivative instruments settled during the period primarily from the impact of our oil fixed-price swaps. Prior to or shortly following our filing for reorganization during 2009, the Predecessor Company settled all outstanding derivative instruments, realizing a gain on those instruments due to the low price environment existing at the time of settlement. In connection with entering into our prior credit facility on the Exit Date, we entered into derivative instruments, primarily oil swaps, pursuant to the terms set forth in our prior credit facility. Due to an increase in market prices for oil during the quarter ended December 31, 2009, the Successor Company recorded unrealized losses on derivative instruments of $21.7 million and losses on settlements of $1.0 in the quarter ended December 31, 2009.

As described above, during the year ended December 31, 2010, we redeemed all of the PIK Notes at 100% of the outstanding aggregate principal amount, plus accrued and unpaid interest. As a result, we recorded a loss on extinguishment of debt totaling

$5.6 million.

Chapter 11 Reorganization

Our reorganization under Chapter 11 in 2009 substantially reduced our indebtedness and restructured our balance sheet. Throughout the course of our Chapter 11 reorganization, we continued to operate in the ordinary course of business without the sale of any assets and continued to meet our business obligations to our vendors and joint interest owners. We emerged from our Chapter 11 reorganization with an improved capital structure and enhanced financial flexibility.

Prior to our filing for reorganization under Chapter 11, a number of events and economic conditions negatively impacted our business and liquidity, including the following: hurricanes in August and September of 2008 damaged third party production pipelines, causing us to shut-in a significant amount of our production from September 2008 and continuing into early 2009; oil and natural gas prices declined in the fourth quarter of 2008 and remained at relatively low levels during 2009 relative to the levels in 2008; and the worldwide credit and capital markets collapsed in 2008 and the availability of debt and equity financing became significantly more scarce, thus reducing financial flexibility for most companies, including us. These factors negatively impacted our business, and led to several circumstances that significantly affected our liquidity, including those described below. Our inability to satisfy these obligations in a timely manner ultimately led to our filing for reorganization under Chapter 11 on May 1, 2009:

- in the third quarter of 2008, the Minerals Management Service (the MMS) (now the BOEM and BSEE) rejected our request for a waiver of supplemental bonding requirements for the decommissioning of certain of our federal offshore properties, resulting in the requirement for us to provide cash or other financial support totaling $47.3 million;

- in March 2009, we received a notice of redetermination from Bank of America, N.A., the Administrative Agent under the Predecessor Company s Credit Agreement dated as of April 23, 2007, that our borrowing base had been reduced from $150.0 million to $45.0 million, resulting in a borrowing base deficiency of $38.0 million that was required to be repaid by April 3, 2009 (which date was ultimately extended to May 1, 2009); and

- on April 15, 2009, we were required to make scheduled interest payments of approximately $17 million on the Predecessor Company s 9.75% Senior Unsecured Notes due 2014 and its Senior Floating Notes due 2013.

On the Exit Date, we consummated certain transactions contemplated by the Plan of Reorganization, including entering into a senior secured credit facility consisting of a $125.0 million revolving credit facility with an initial borrowing base of $45.0 million and a $25.0 million one-year amortizing term loan facility. On the Exit Date, we drew $25.0 million under the revolving credit facility. We also issued 20% Senior Subordinated Secured PIK Notes due 2014 in an aggregate original principal amount of $61.1 million with original issue discount for net proceeds of $55.0 million. The proceeds from the credit facility and the PIK Notes were used to repay amounts outstanding of $83.0 million under the Pre-Reorganization Credit Agreement and to provide working capital for the Company. We also converted the Predecessor Company s 9.75% Senior Unsecured Notes due 2014, its Senior Floating Rate Notes due 2013 and its 8.75% Senior Notes due 2010, in an aggregate principal amount of approximately $454.5 million (collectively the Predecessor Company Notes) and all outstanding shares of the Predecessor Company s common stock into shares of the Successor Company s common stock. In accordance with the terms of the Plan of Reorganization, the Predecessor Company Notes and related indentures were cancelled and each existing holder of the Predecessor Company Notes received, in exchange for such holder s claim (including principal and accrued interest), such holder s pro rata portion of approximately 95% of the Successor Company s common stock. Each holder of shares of the Predecessor Company s common stock received, in full satisfaction of and in exchange for such holder s interest in the common stock of the Predecessor Company, such holder s pro rata portion of approximately 5% of the Successor Company s common stock.

Our Chapter 11 reorganization and related matters are also addressed in Note 17, Reorganization and Fresh-Start Accounting to our consolidated financial statements contained in Part II, Item 8, Financial Statements and Supplementary Data.

Liquidity and Capital Resources

At December 31, 2011, we had unrestricted cash on hand of approximately $80.1 million and no amounts drawn under our credit facility, which currently has a borrowing base of $200 million. Our fiscal year 2012 capital budget is $168 million, of which $110 million is allocated to development activities and $58 million to exploration projects within existing core field areas including seismic purchases. Additionally, we plan to spend approximately $27 million in 2012 on plugging, abandonment and other decommissioning activities. We intend to finance our capital expenditure budget and plugging and abandonment expenditures with cash flow from operations.

Sources and Uses of Capital

As of December 31, 2011, we had cash and cash equivalents of $80.1 million and no amounts drawn under our credit facility (described below). At the closing of our 8.25% Notes offering on February 14, 2011, our prior credit facility was replaced with our credit facility, which had an initial borrowing base of $150.0 million and was recently increased to $200.0 million.

Capital Expenditures. During 2011, we spent approximately $101 million on development and exploration activities, $84 million on our development efforts and $17 million on exploration projects. During 2011, we focused our development efforts on our Gulf of Mexico shelf asset base, primarily our oil-rich East Bay field as well as the Greater Bay Marchand and West Delta areas. We also spent approximately $32 million on plugging, abandonment and other decommissioning activities during 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. We financed the ASOP Acquisition with the proceeds from the sale of $210 million in aggregate principal amount of 8.25% senior notes due 2018 (described below). After deducting the initial purchasers discount and estimated offering expenses, we realized net proceeds of approximately $202 million from the sale of the 8.25% Notes. 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. We funded the Main Pass Acquisition with cash on hand. We may fund future acquisitions with a combination of cash on hand, borrowings on our credit facility and issuances of one or more debt and equity securities under our universal shelf registration statement that became effective under the Securities Act of 1933 in July 2011.

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. 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. Through the date of this report, we have repurchased 1,019,000 shares at an aggregate cash purchase price of approximately $12.8 million. 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.

Working Capital. At December 31, 2011, we had working capital of $10.2 million, compared to a working capital deficit of $12.7 million at December 31, 2010. We have experienced, and may experience in the future, substantial 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.

Restricted Cash. We maintain restricted escrow funds in a trust for future plugging, abandonment and other decommissioning costs at our East Bay field. The trust was originally funded with $15.0 million and, with accumulated interest, had increased to $16.7 million at December 31, 2008. We have made draws to date of $10.7 million, with $2.5 million drawn in 2011. We were able to draw from the trust upon the authorization, and subsequent completion, of qualifying

abandonment activities at our East Bay field. As of the date of this Annual Report, we had $6.0 million remaining in restricted escrow funds 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 condensed consolidated balance sheets.

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.

8.25% Notes. On February 14, 2011, we issued $210 million in aggregate principal amount of the 8.25% Notes. We used the net proceeds from the offering of the 8.25% Notes of $202 million, after deducting the initial purchasers discount and estimated 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. The 8.25% Notes bear interest from the date of their issuance at an annual rate of 8.25% with interest on outstanding notes payable semi-annually, in arrears, on February 15 and August 15 of each year, commencing on August 15, 2011. The 8.25% 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% Notes will mature on February 15, 2018. For more information on our 8.25% 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 a new credit facility with BMO Capital Markets, as lead arranger, Bank of Montreal, as administrative agent and a lender. Under the terms of the credit agreement, this credit facility established a revolving credit facility with a four-year term that may be used for revolving credit loans and letters of credit up to an aggregate principal amount of $250 million, subject to an initial borrowing base of $150 million. The credit facility is secured by substantially all of our assets, including mortgages on at least 85% of our oil and gas properties and the stock of certain wholly-owned subsidiaries. The borrowing base under the 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. In November 2011, we completed our semi-annual redetermination and our borrowing base was increased to $200 million. Borrowings under our credit facility bear interest ranging from a base rate plus a margin of 1.00% to 2.00% on base rate borrowings and LIBOR plus a margin of 2.00% to 3.00% on LIBOR borrowings. Our credit facility was undrawn at closing and currently remains undrawn.

Terminated Credit Facility. We terminated the then existing prior credit facility (the Prior Credit Facility) in connection with entering into our current credit facility described above. A key focus of management in 2010 was to reduce our cost of capital. On June 16, 2010, we entered into an amendment (the First Amendment) to our Prior Credit Facility (the Amended Prior Credit Facility) with General Electric Capital Corporation, as administrative agent (the Agent), and the lender parties thereto (the Lenders). Upon its effectiveness on June 28, 2010, our Amended Prior Credit Facility established a $70 million borrowing base consisting of (a) a new $25 million term loan payable, with interest, in six equal monthly installments of principal from July 28, 2010 to December 28, 2010 and (b) a revolving credit facility with a three-year term that could be used for revolving credit loans and letters of credit up to an initial maximum principal amount of $45 million. The interest rate spread on loans and letters of credit under our Amended Prior Credit Facility was based on the level of utilization and ranged from 3.75% to 4.25% for base rate borrowings and 4.75% to 5.25% for LIBOR borrowings. The First Amendment contained the Lenders consent for us to redeem all outstanding principal and pay all accrued interest on our PIK Notes, which redemption occurred on June 28, 2010 and was a condition to the effectiveness of the First Amendment. We redeemed all of the PIK Notes at 100% of the outstanding aggregate principal amount, plus accrued and unpaid interest. As a result, during 2010, we recorded a loss on extinguishment of debt totaling $5.6 million which represented the total of the unamortized original issue discount and unamortized deferred financing costs associated with the PIK Notes. We used cash on hand and a portion of the proceeds of the new term loan under our Amended Prior Credit Facility to fund the redemption.

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Analysis of Cash Flows for the Year Ended December 31, 2011

The following table sets forth our cash flows:

	Year Ended December 31, 2011	2010
	(in thousands)	
Net cash provided by operating activities	$ 171,252	$ 127,380
Net cash used in investing activities	$ (310,591)	$ (45,903)
Net cash provided by (used in) financing activities	$ 185,914	$ (74,669)

The increase in our 2011 cash flows from operations primarily reflects increases in revenues due to the increase in oil prices and our oil production, partially offset by decreases in revenues due to the decline in natural gas production during the year ended December 31, 2011 as compared to the year ended December 31, 2010. In addition, cash flows from operations reflects increased spending on plugging, abandonment and decommissioning activities during the year ended December 31, 2011, as compared to the year ended December 31, 2010.

Net cash used in investing activities increased in the year ended December 31, 2011 as compared to the year ended December 31, 2010, primarily as a result of our acquisition of the ASOP Properties and the Main Pass Interests and an increase in our exploration and development expenditures during the year ended December 31, 2011.

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 8.25% Notes, partially offset by expenditures of $6.6 million for financing costs primarily associated with our current senior credit facility and the offering expenses associated with our 8.25% Notes. 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 during the year ended December 31, 2011. Net cash used in financing activities during the year ended December 31, 2010 reflects the redemption of the PIK Notes and payments on the term loan component of our Prior Credit Facility and our Amended Prior Credit Facility, partially offset by proceeds from the term loan component of our Amended Prior Credit Facility.

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 new senior credit facility and the Indenture governing the 8.25% 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, 2010

The following table sets forth our cash flows:

	Successor Company Year Ended December 31, 2010	Successor Company Period from October 1 through December 31, 2009	Predecessor Company Period from January 1 through September 30, 2009
		(in thousands)	
Net cash provided by operating activities	$ 127,380	$ 16,868	$ 14,366
Net cash used in investing activities	$ (45,903)	$ (2,808)	$ (29,751)
Net cash provided by (used in) financing activities	$ (74,669)	$ (31,250)	$ 57,329

The increase in our 2010 cash flows from operations primarily reflected the impact of the increase in oil and natural gas sales prices realized during the year ended December 31, 2010 as compared to the year ended December 31, 2009. Operating cash flows for the year ended December 31, 2010 also included cash payments totaling $15.8 million related to the redemption of our PIK Notes on June 28, 2010, which amount included $9.7 million of interest for the period from September 21, 2009 through the redemption date and $6.1 million of original issue discount.

Net cash used in investing activities in the year ended December 31, 2010 reflected an increase in exploration and development expenditures as compared to the year ended December 31, 2009, offset by a decrease in restricted cash. Our investing cash flows for the year ended December 31, 2009 reflected, in part, that a higher level of capital expenditure activities occurred in the fourth quarter of 2008 compared to the fourth quarter of 2009, which resulted in cash payments for prior quarter work during the quarter ended March 31, 2009 that were higher than those in the quarter ended March 31, 2010.

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Net cash used in financing activities during the year ended December 31, 2010 reflected the redemption of the PIK Notes and payments on the term loan component of our Prior Credit Facility and our Amended Prior Credit Facility, partially offset by proceeds from the term loan component of our Amended Prior Credit Facility. Net cash provided by financing activities during the year ended December 31, 2009 reflected increased utilization of the Predecessor Company s credit facility to fund working capital shortfalls caused by the decline in production and the precipitous decline in oil and natural gas sales prices in 2009.

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, 2011.

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years (in thousands)	3-5 Years	Thereafter
Indebtedness	$ 210,000	$	$	$	$ 210,000
Interest on indebtedness	112,612	17,325	34,650	34,650	25,987
Operating leases	5,204	821	1,854	1,934	595
Asset retirement obligations including accretion	234,274	25,578	18,026	13,384	177,286
Total contractual obligations	$ 562,090	$ 43,724	$ 54,530	$ 49,968	$ 413,868

Off-Balance Sheet Transactions

We do not maintain any off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities or others that are reasonably likely to have a material current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources other than those 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 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 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 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). In December 2008, the SEC issued a final rule, Modernization of Oil and Gas Reporting, which amended its oil and gas reserves estimation and disclosure requirements. The new requirements were codified into ASC 932 in January 2010 and had the effect of, among other things: permitting the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes; modifying the prices used to estimate reserves for SEC disclosure purposes to an unweighted, arithmetic average price based upon the prior twelve month period rather than the year-end price; and allowing the optional disclosure of probable and possible reserves to investors. The revised rule was effective January 1, 2010 for reporting December 31, 2009 annual oil and natural gas reserve information. We adopted the provisions of the final rule in connection with the preparation of our 2009 Annual Report. 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, 2011, we had estimated proved reserves of 37.1 Mmboe, of which 53% were proved developed producing reserves while 38% 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 9% of total proved reserves are categorized as proved undeveloped reserves.

The present value of the future net cash flow 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, 2011, 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 $108.48 per barrel and a natural gas price based on the NYMEX Henry Hub of $4.16 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 produced to (2) total proved developed reserves (those proved reserves recoverable through existing wells with existing equipment and operating methods), or total proved reserves in the case of leasehold costs (the DD&A rate). Each period, this ratio 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. As previously discussed, material revisions to proved reserves may occur as a result of unforeseen factors and may materially impact the DD&A rate.

In 2010, we had negative revisions of 4.3 Mmboe related to PUDs aged greater than five years for which funds were not committed in our 2011 development plan, representing 14% of our total proved reserves of 31.2 Mmboe as of December 31, 2009. In 2009, we had negative revisions of 0.6 Mmboe, representing 2% of our total proved reserves of 36.8 Mmboe as of December 31, 2008. 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 separately, property by property (generally analogous to a field or a lease), 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, 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 $32.5 million, $26.1 million, $8.5 million and $8.1 million in the year ended December 31, 2011, in the year ended December 31, 2010, in the period from October 1, 2009 through December 31, 2009 and in the period from January 1, 2009 through September 30, 2009, respectively.

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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 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 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 price of oil and natural gas. Historically, our hedging instruments have consisted primarily of financially-settled puts, swaps and collars. We record our hedging instruments at 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 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 grant-date fair value. Our estimate of the forfeiture rate of our share-based awards also impacts the amount of expense recorded over the expected life 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 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.

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Reorganization and Fresh-Start Accounting The financial statements for the period in which we were in reorganization under Chapter 11 were prepared in accordance with ASC Topic 852, Reorganizations, (originally issued as the American Institute of Certified Public Accountant s Statement of Position 90-7, Financial Reporting by Entities in Reorganization Under the Bankruptcy Code). Under ASC 852, we were required to, among other things, (1) identify transactions that were directly associated with the reorganization from those events that occurred during the normal course of business, (2) identify pre-petition liabilities subject to compromise from those that were not subject to compromise or were post-petition liabilities and (3) apply fresh-start accounting rules upon emergence from Chapter 11 reorganization.

In accordance with ASC 852, 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.

Based on financial projections that we and our advisors developed, the allocation of the reorganization value was determined using various valuation methods, including (i) comparable company analysis, which estimates the value of the Company based on the implied valuations of other similar companies; (ii) comparable asset transaction analysis, which estimates the value of a company based upon publicly announced transactions of assets with similar characteristics; (iii) comparable merger transaction analysis, which, much like comparable asset transaction analysis, estimates the value of a company based upon publicly announced transactions with similar characteristics, except that merger analysis analyzes public to public merger transactions rather than solely asset transactions; and (iv) discounted cash flow analysis, which estimates the value of the Company by determining the present value of estimated future cash flows. The reorganization value is based on subjective estimates and assumptions, which are inherently subject to significant uncertainties and contingencies which are beyond our control. The fair value allocated to our property and equipment should not be viewed as representative of the current value of our oil and natural gas reserves or the current value of the Company. The reorganization value of the Company was estimated to be approximately $603 million.

In order to reflect the reorganization and application of ASC 852, we adjusted the book values of the Predecessor Company s assets and liabilities to reflect the estimated fair values of the Successor Company s assets and liabilities, on a net basis. These adjustments reduced our net loss by $57.1 million in the period from January 1, 2009 through September 30, 2009. The restructuring of the Company s capital and resulting discharge of the Predecessor Company Notes and related accrued interest resulted in a loss of $2.7 million in the period from January 1, 2009 through September 30, 2009. The adjustments for the revaluation of the assets and liabilities and the loss on the discharge of pre-petition debt were recorded in Fresh-start adjustments and Loss on discharge of debt, respectively, in the consolidated statement of operations for the period from January 1, 2009 through September 30, 2009.

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 credit facility. Currently, we do not use interest rate derivative instruments to manage exposure to interest rate changes. Borrowings under our credit facility bear interest ranging from a base rate plus a margin of 1.00% to 2.00% on base rate borrowings and LIBOR plus a margin of 2.00% to 3.00% on LIBOR borrowings. We had no amounts drawn under our credit facility at December 31, 2011 or under our prior credit facility at December 31, 2010. In addition, we did not borrow under our credit facility during the year ended December 31, 2011. At December 31, 2011, our total indebtedness outstanding consisted of $204.4 million (net of unamortized original purchasers discount of $5.6 million) related to our fixed-rate 8.25% Notes which mature on February 15, 2018. The estimated fair value of our 8.25% Notes was approximately $202.7 million at December 31, 2011.

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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 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.

Historically, we have used commodity derivative instruments to manage commodity price risks associated with future oil and natural gas production. As of December 31, 2011, the following derivative instruments were outstanding:

Oil Contracts

	Fixed-Price Swaps			
Remaining Contract Term	**Daily Average Volume (Bbls)**	**Volume (Bbls)**	**Average Swap Price ($/Bbl)**	**Fair Value (In thousands)**
January 2012 July 2012	3,880	826,500	$ 100.44	$ (1,537)
August 2012 November 2012	2,721	332,000	$ 103.76	$ 360
December 2012	3,161	98,000	$ 102.47	$ 121
January 2013 July 2013	2,471	523,900	$ 97.84	$ (145)
August 2013 November 2013	426	52,000	$ 94.18	$ (38)
December 2013	806	25,000	$ 93.98	$ (7)

	Collars			
Remaining Contract Term	**Daily Average Volume (Bbls)**	**Volume (Bbls)**	**Strike Price ($/Bbl)**	**Fair Value (In thousands)**
January 2012 July 2012	1,000	213,000	$ 87.50/123.18	$ 207
August 2012 November 2012	1,000	122,000	$ 87.50/123.18	$ 291
December 2012	1,000	31,000	$ 87.50/123.18	$ 89

During January and February 2012, we entered into the following derivative instruments:

Oil Contracts

	Fixed-Price Swaps		
Remaining Contract Term	**Daily Average Volume (Bbls)**	**Volume (Bbls)**	**Average Swap Price ($/Bbl)**
July 2013 December 2013	450	165,600	$ 104.30

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Energy Partners, Ltd.:

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 Energy Partners, Ltd. and its subsidiaries (the Company) at December 31, 2011 and December 31, 2010, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2011 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, 2011, based on criteria established in *Internal Control Integrated Framework* 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.

/S/ PricewaterhouseCoopers LLP

New Orleans, Louisiana

March 8, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

Energy Partners, Ltd.:

We have audited the accompanying consolidated statements of operations, changes in stockholders equity, and cash flows of Energy Partners, Ltd. and subsidiaries for the period from October 1, 2009 through December 31, 2009 (Successor Company) and for the period from January 1, 2009 through September 30, 2009 (Predecessor Company). These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the results of operations and cash flows of Energy Partners, Ltd. and subsidiaries for the period from October 1, 2009 through December 31, 2009 (Successor Company) and for the period from January 1, 2009 through September 30, 2009 (Predecessor Company), in conformity with U.S. generally accepted accounting principles.

As discussed in note 1 and note 17 to the consolidated financial statements, the Company filed a petition for reorganization under Chapter 11 of the United States Bankruptcy Code on May 1, 2009. The Company s plan of reorganization became effective, and the Company emerged from bankruptcy protection on September 21, 2009. In connection with its emergence from bankruptcy, the Successor Company Energy Partners, Ltd. and subsidiaries adopted fresh-start reporting in conformity with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 852 (ASC 852), *Reorganizations*. Accordingly, the Successor Company s consolidated financial statements prior to September 30, 2009 are not comparable to its consolidated financial statements for periods on or after September 30, 2009.

/s/ KPMG LLP

New Orleans, Louisiana

March 10, 2010, except for the supplemental condensed consolidating statement of operations and cash flows for the period from October 1, 2009 through December 31, 2009 (Successor Company), and for the period from January 1, 2009 through September 30, 2009 (Predecessor Company) as presented in note 16, which is as of March 2, 2011.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

December 31, 2011 and 2010

(In thousands, except share data)

	2011	2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 80,128	$ 33,553
Trade accounts receivable net	31,817	21,443
Receivables from insurance		2,088
Fair value of commodity derivative instruments	587	186
Deferred tax assets		2,693
Prepaid expenses	11,046	3,303
Total current assets	123,578	63,266
Property and equipment, under the successful efforts method of accounting for oil and natural gas properties	1,082,248	719,147
Less accumulated depreciation, depletion and amortization	(305,110)	(168,055)
Net property and equipment	777,138	551,092
Restricted cash	6,023	8,489
Other assets	3,029	1,814
Deferred financing costs net of accumulated amortization of $1,061 and $1,656 at December 31, 2011 and 2010, respectively	5,452	2,245
	$ 915,220	$ 626,906
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 25,393	$ 18,358
Accrued expenses	58,538	28,394
Asset retirement obligations	25,578	16,902
Fair value of commodity derivative instruments	1,056	12,320
Deferred tax liabilities	2,823	
Total current liabilities	113,388	75,974
Long-term debt	204,390	
Asset retirement obligations	73,769	54,681
Deferred tax liabilities	31,775	22,469
Fair value of commodity derivative instruments	190	
Other	663	666
	424,175	153,790
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, 2011 and 2010		
Common stock, par value $0.001 per share; authorized 75,000,000 shares; shares issued 40,326,451 and 40,091,664 at December 31, 2011 and 2010, respectively; shares outstanding 39,404,106 and 40,091,664 at December 31, 2011 and 2010,respectively	40	40

Additional paid-in capital	505,235	502,556
Treasury stock, at cost, 922,345 shares at December 31, 2011	(11,361)	
Accumulated deficit	(2,869)	(29,480)
Total stockholders equity	491,045	473,116
	$ 915,220	$ 626,906

See accompanying notes to consolidated financial statements.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

For the Years Ended December 31, 2011 and 2010, the Period from October 1, 2009 through December 31, 2009 and

the Period from January 1, 2009 through September 30, 2009

(In thousands, except per share data)

	SUCCESSOR COMPANY			PREDECESSOR COMPANY
	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
Revenue:				
Oil and natural gas	$ 348,207	$ 239,770	$ 56,708	$ 134,583
Other	120	139	42	302
	348,327	239,909	56,750	134,885
Costs and expenses:				
Lease operating	70,281	52,365	13,410	46,296
Transportation	779	1,306	315	699
Exploration expenditures and dry hole costs	14,268	6,441	453	1,650
Impairments	32,466	26,142	8,514	8,082
Depreciation, depletion and amortization	104,624	104,561	28,448	95,944
Accretion of liability for asset retirement obligations	15,942	12,845	3,024	5,536
General and administrative	18,741	18,078	4,537	19,493
Taxes, other than on earnings	14,365	10,133	2,083	5,987
Other	9,735	729	489	3,706
Total costs and expenses	281,201	232,600	61,273	187,393
Business interruption recovery				1,185
Income (loss) from operations	67,126	7,309	(4,523)	(51,323)
Other income (expense):				
Interest income	102	113	3	47
Interest expense (contractual interest of $34,076 for the period from January 1, 2009 through September 30, 2009)	(17,548)	(9,807)	(4,322)	(17,813)
Gain (loss) on derivative instruments	(5,870)	(4,865)	(22,705)	2,728
Loss on early extinguishment of debt	(2,377)	(5,627)		
	(25,693)	(20,186)	(27,024)	(15,038)
Income (loss) before reorganization items, loss on discharge of debt, fresh-start adjustments and income taxes	41,433	(12,877)	(31,547)	(66,361)
Reorganization items (Note 17)			(865)	(24,198)
Loss on discharge of debt (Note 17)				(2,666)
Fresh-start adjustments (Note 17)				57,111
Income (loss) before income taxes	41,433	(12,877)	(32,412)	(36,114)
Deferred income tax benefit (expense)	(14,822)	4,409	11,400	

Net income (loss)	26,611	(8,468)	(21,012)	(36,114)
Basic income (loss) per share	$ 0.66	$ (0.21)	$ (0.53)	$ (1.12)
Diluted income (loss) per share	$ 0.66	$ (0.21)	$ (0.53)	$ (1.12)
Weighted average common shares used in computing earnings per share:				
Basic	39,946	40,064	40,020	32,200
Diluted	40,050	40,064	40,020	32,200

See accompanying notes to consolidated financial statements.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY

For the Years Ended December 31, 2011 and 2010, the Period from October 1, 2009 through December 31, 2009, and

the Period from January 1, 2009 through September 30, 2009

(In thousands)

	Treasury Stock Shares	Treasury Stock	Predecessor Company Common Stock Shares	Predecessor Company Common Stock	Successor Company Common Stock Shares	Successor Company Common Stock	Additional Paid In Capital	Retained Earnings (Accumulated Deficit)	Total
Balance, December 31, 2008 Predecessor Company	12,240	$ (258,356)	44,323	$ 444			$ 382,232	$ (67,201)	$ 57,119
Stock option and restricted share awards			297	2	18		3,420		3,422
Net loss								(36,114)	(36,114)
Other			54	1			616		617
Reorganization Adjustments	(12,240)	258,356	(44,674)	(447)	40,000	40	114,566	103,315	475,830
Balance, September 30, 2009 Successor Company		$		$	40,018	$ 40	$ 500,834	$	$ 500,874
Stock option and restricted share awards							243		243
Net loss								(21,012)	(21,012)
Other					4		(18)		(18)
Balance, December 31, 2009 Successor Company		$		$	40,022	$ 40	$ 501,059	$ (21,012)	$ 480,087
Stock option and restricted share awards					69		1,429		1,429
Net loss								(8,468)	(8,468)
Other					1		68		68
Balance, December 31, 2010 Successor Company		$		$	40,092	$ 40	$ 502,556	$ (29,480)	$ 473,116
Stock option and restricted share awards	6	(8)			217		2,509		2,501
Exercise of stock options					13		119		119
Purchase of shares into treasury	916	(11,353)							(11,353)
Net income								26,611	26,611
Other					4		51		51
Balance, December 31, 2011 Successor Company	922	$ (11,361)		$	40,326	$ 40	$ 505,235	$ (2,869)	$ 491,045

See accompanying notes to consolidated financial statements.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2011 and 2010, the Period from October 1, 2009 through December 31, 2009 and

the Period from January 1, 2009 through September 30, 2009

(In thousands)

	SUCCESSOR COMPANY			PREDECESSOR COMPANY
	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
Cash flows from operating activities:				
Net income (loss)	$ 26,611	$ (8,468)	$ (21,012)	$ (36,114)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation, depletion and amortization	104,624	104,561	28,448	95,944
Accretion of liability for asset retirement obligations	15,942	12,845	3,024	5,536
Loss on discharge of debt				2,666
Fresh-start adjustments				(57,111)
Unrealized (gain) loss on derivative contracts	(11,475)	(3,500)	21,739	
Non-cash compensation	2,509	1,255	417	3,689
In-kind interest on PIK Notes		(3,395)	3,395	
Deferred income taxes	14,822	(4,409)	(11,400)	
Exploration expenditures	11,239	5,103	163	126
Impairments	32,466	26,142	8,514	8,082
Amortization of deferred financing costs and discount on debt	1,657	1,130	524	8,356
Loss on early extinguishment of debt	2,377			
Other	6,984	(90)	493	3,735
Changes in operating assets and liabilities:				
Trade accounts receivable	(10,037)	6,515	(3,501)	4,807
Other receivables	2,088	3,376	(1,428)	194
Prepaid expenses	(7,623)	(363)	1,505	677
Other assets	(1,215)	618	(1,570)	(641)
Accounts payable and accrued expenses	12,650	2,361	(10,806)	(2,414)
Asset retirement obligations	(32,364)	(16,130)	(1,637)	(22,374)
Other liabilities	(3)	(171)		(792)
Net cash provided by operating activities	171,252	127,380	16,868	14,366
Cash flows used in investing activities:				
Decrease in restricted cash	2,466	13,658		
Property acquisitions	(235,486)	(623)	(54)	(31)
Exploration and development expenditures	(76,003)	(58,183)	(2,731)	(29,723)
Other property and equipment additions	(1,568)	(755)	(23)	(147)
Proceeds from sale of oil and gas assets				150
Net cash used in investing activities	(310,591)	(45,903)	(2,808)	(29,751)

Cash flows provided by (used in) financing activities:				
Proceeds from indebtedness	203,794	20,394		113,128
Deferred financing costs	(6,646)	(181)		(798)
Purchase of shares into treasury	(11,353)			
Exercise of stock options	119			
Repayments of indebtedness		(94,882)	(31,250)	(55,001)
Net cash provided by (used in) financing	185,914	(74,669)	(31,250)	57,329
Net increase (decrease) in cash and cash equivalents	46,575	6,808	(17,190)	41,944
Cash and cash equivalents at beginning of period	33,553	26,745	43,935	1,991
Cash and cash equivalents at end of year	$ 80,128	$ 33,553	$ 26,745	$ 43,935

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	SUCCESSOR COMPANY			PREDECESSOR COMPANY
	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
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:				
Non-cash financing information:				
Discharge of Senior Unsecured Notes	$	$	$	$ 473,164
Issuance of equity in Successor Company				500,874
Debt incurred to repay secured bank credit facility				29,084
Debt incurred to pay deferred financing costs and surety bond premium		737		2,790
Debt incurred to pay interest on PIK Notes			3,395	
Cash paid during the period for:				
Interest	9,395	8,307	552	5,614
Income taxes				

See accompanying notes to consolidated financial statements.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Summary of Significant Accounting Policies

Energy Partners, Ltd. (we, our, us, or the Company) was incorporated as a Delaware corporation on January 29, 1998. We are 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.

On February 14, 2011, we acquired 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 from Anglo-Suisse Offshore Partners, LLC (ASOP) for $200.7 million in cash, subject to customary adjustments to reflect an economic effective date of January 1, 2011 (the ASOP Acquisition). In connection with the ASOP Acquisition, on February 14, 2011, we issued $210.0 million in aggregate principal amount of 8.25% senior notes due 2018 (the 8.25% Notes) and we entered into a new credit facility. On November 17, 2011, we acquired additional interests in the Main Pass 296/311 complex that was included in the ASOP Acquisition 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 in cash, subject to customary adjustments to reflect an economic effective date of November 1, 2011 (the Main Pass Acquisition). See Note 2, Acquisitions for more information regarding these acquisitions and Note 7, Indebtedness for more information regarding the 8.25% Notes and our credit facility.

On May 1, 2009 (the Petition Date), we and certain of our subsidiaries filed voluntary petitions (In re: Energy Partners, Ltd., et. al., Case No. 09-32957) for reorganization under Chapter 11 of Title 11 of the United States Code, 11 U.S.C. §§ 101 et seq., as amended (Chapter 11), in the United States Bankruptcy Court for the Southern District of Texas, Houston Division (the Bankruptcy Court). We continued to manage our properties and operate our business as debtors-in-possession while under the jurisdiction of the Bankruptcy Court. On September 21, 2009, we emerged from Chapter 11 reorganization (the Exit Date) pursuant to the plan of reorganization confirmed by the Bankruptcy Court (the Plan of Reorganization). The Chapter 11 filings and related matters are addressed in Note 17, Reorganization and Fresh-Start Accounting.

A summary of significant accounting policies followed in the preparation of the accompanying consolidated financial statements is set forth below.

(a) Basis of Presentation

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States (GAAP) and include the accounts of Energy Partners, Ltd. and our wholly-owned subsidiaries. All significant intercompany accounts and transactions are eliminated in consolidation. Our interests in oil and natural gas exploration and production ventures and partnerships are proportionately consolidated.

The financial statements for the period in which the Company was in reorganization under Chapter 11 were prepared in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 852 (ASC 852), Reorganizations, (originally issued as the American Institute of Certified Public Accountant s Statement of Position 90-7, Financial Reporting by Entities in Reorganization Under the Bankruptcy Code). In accordance with ASC 852, 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 was deemed created for financial reporting purposes. References to the Predecessor Company refer to reporting dates of the Company through September 30, 2009, including the effect of the reorganization and application of fresh-start accounting; subsequent thereto, the Company is referred to as the Successor Company in the consolidated financial statements and the notes thereto. For further information on fresh-start accounting, see Note 17, Reorganization and Fresh-Start Accounting.

(b) Property and Equipment

We use 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.

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Leasehold acquisition costs are capitalized. If proved reserves are found on an undeveloped property, leasehold costs are transferred to proved properties. For individual unevaluated properties with capitalized cost below a threshold amount, we allocate capitalized costs to earnings generally 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. Capitalized costs of producing oil and natural gas properties are depreciated and depleted by the units-of-production method.

We evaluate our capitalized costs of proved oil and natural gas properties for potential impairment when circumstances indicate that the carrying values may not be recoverable. 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, or other changes to contracts, environmental regulations or tax laws. The calculation is performed on a field-by-field basis, utilizing our current estimates of future revenues and operating expenses. In the event net undiscounted cash flow is less than the carrying value, an impairment loss is recorded based on the present value of expected future net cash flows over the economic lives of the reserves.

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depletion, depreciation and amortization are eliminated from the property accounts, along with the related asset retirement obligations, unless retained by us, and the resulting gain or loss is recognized in earnings.

(c) Asset Retirement Obligations

We record our obligations associated with the retirement of tangible long-lived assets at their fair values in the period incurred. The fair value of the obligation is also recorded to the related asset s carrying amount. Accretion of the liability is recognized as an operating expense and the capitalized cost is amortized using the units-of-production method. We revise our estimates of asset retirement obligations as information about material changes to the liability becomes known. Revisions are recorded as adjustments to existing liabilities and to the carrying amount of the related assets. Revisions occurring at or near the end of an asset s useful life may materially impact earnings. Our asset retirement obligations relate primarily to the plugging and abandonment of our oil and natural gas wellbores and to decommissioning related pipelines, facilities and structures.

(d) Income Taxes

We account for income taxes under the asset and liability method, which requires that we recognize deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis amounts. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. We recognize the effect on deferred tax assets and liabilities of a change in the tax rates in income in the period that includes the enactment date.

We follow the provisions of ASC Topic 740, Income Taxes, which apply to the accounting for uncertainty in income taxes recognized in an enterprise s financial statements and prescribe a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. These provisions also contain guidance on de-recognition, classification, interest and penalties. Interest, if any, is classified as a component of interest expense, and statutory penalties, if any, are classified as a component of general and administrative expense.

(e) Deferred Financing Costs

We defer costs incurred to obtain debt financing and then amortize such costs as additional interest expense over the maturity period of the related debt.

(f) Earnings Per Share

Basic earnings per share is computed by dividing income or loss available to common stockholders by the weighted average number of common shares outstanding during each period. According to GAAP, we have determined that our unvested restricted share awards, which contain non-forfeitable rights to dividends, are participating securities and should be included in the computation of earnings per share pursuant to the two-class method. The two-class method allocates undistributed earnings between common shares and participating securities. The diluted earnings per share calculation under the two-class method also includes the effect, if dilutive, of potential common shares associated with stock option awards outstanding during each period. The dilutive effect of stock options is determined using the treasury stock method.

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(g) Revenue Recognition

We record revenues from the sales of oil and natural gas when the product is delivered at a determinable price, title has transferred and collectability is reasonably assured. When we have an interest with other producers in properties from which natural gas is produced, we use the entitlement method for recording natural gas sales revenue. Under this method of accounting, revenue is recorded based on our net revenue interest in production. Deliveries of natural gas in excess of our revenue interest are recorded as liabilities and under-deliveries are recorded as receivables. We had natural gas imbalance liabilities of $1.6 million at December 31, 2011 and 2010. We had natural gas imbalance receivables of $1.0 million at December 31, 2011.

(h) Cash and Cash Equivalents

We include in cash and cash equivalents our highly-liquid investments with original maturities of three months or less. At December 31, 2011 and 2010, cash and cash equivalents includes investments in overnight interest-bearing deposits of $51.8 million and $35.8 million, respectively. These amounts are reduced by overdraft balances on other operating accounts with legal right of offset in the same banking institution to arrive at the cash and cash equivalent balances reported in our consolidated balance sheets.

(i) Derivative Activities

Derivative instruments, including certain derivative instruments embedded in other contracts, are recorded at fair market value and included as either assets or liabilities in the balance sheet. The accounting for changes in fair value depends on the intended use of the derivative and the resulting designation, which is established at the inception of the derivative. We do not elect to designate derivative instruments as hedges. Unrealized gains and losses resulting from changes in the fair value of derivative instruments are recorded in other income (expense). Realized gains and losses related to contract settlements are also recorded in other income (expense).

(j) Share-Based Compensation

We recognize share-based compensation expense based on the estimated grant-date fair value of all share-based awards, net of an estimated forfeiture rate, over the requisite service period of the awards, which is generally equivalent to the vesting term. We record share-based compensation expense only for those awards expected to vest. We periodically revise our estimated forfeiture rate if actual forfeitures differ from our estimates.

We are required to report excess tax benefits from the exercise of stock options as financing cash flows. For the year ended December 31, 2011, no excess tax benefits were reported in the statement of cash flows as we were in a net operating loss carryforward position. No stock options were exercised during 2010 and 2009. See Note 12 for additional disclosures.

(k) Allowance for Doubtful Accounts

We routinely assess the recoverability of all material trade and other receivables to determine their collectability. Our crude oil and natural gas revenue receivables are typically collected within two months. We may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest receivables on properties where we are the operator. When we believe collection of the full amount of our accounts receivable is in doubt, we record an allowance to reflect accounts receivable at the net realizable value, which may be reflected in earnings or as an increase to the net book value of our oil and natural gas properties depending on the nature of the transaction that created the receivable. The nature of the transaction resulting in the receivable balance determines whether the allowance, when recorded, impacts our earnings (ordinarily through LOE) or our property and equipment balances. As of December 31, 2011, our allowance for doubtful accounts was $1.7 million, $0.5 million of which was recorded as a recovery in earnings in 2011. As of December 31, 2010, our allowance for doubtful accounts was $2.3 million, $0.3 million of which was recorded as a reduction in earnings in 2010.

(l) Accrued Expenses

As of December 31, 2011, our accrued expenses included accrued exploration costs, development costs and lease operating expenses totaling approximately $39.5 million, other accrued expenses of $12.5 million and accrued interest on indebtedness of approximately $6.5 million. As of December 31, 2010, our accrued expenses included accrued exploration costs, development costs and lease operating expenses totaling approximately $12.2 million and other accrued expenses of $16.2 million. We had no accrued interest on indebtedness at December 31, 2010.

(m) Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Certain

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accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We use historical experience and various other assumptions that are believed to be reasonable under the circumstances to form the basis for making judgments about carrying values of assets and liabilities that are not readily apparent from other sources. Our actual results may differ from these estimates and assumptions used in preparation of our financial statements. Significant estimates with regard to these financial statements and related unaudited disclosures include the estimate of proved oil and natural gas reserve quantities and the related present value of estimated future net cash flows therefrom disclosed in Note 15 and the estimated fair values of assets and liabilities used in the application of fresh-start accounting as described in Note 17.

(n) Reclassifications

Certain reclassifications have been made to the prior period financial statements in order to conform to the classification adopted for the most recent reporting period.

(o) New Accounting Pronouncements

In May 2011, the FASB issued Accounting Standards Update (ASU) No. 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs (ASU 2011-04). ASU 2011-04 changes some fair value measurement principles under U.S. GAAP including a change in the valuation premise and the application of premiums and discounts. It also contains certain new disclosure requirements. It is effective for interim and annual periods beginning after December 15, 2011. We expect the impact of adopting ASU 2011-04 to be immaterial.

In December 2011, the FASB issued ASU No. 2011-11, Balance Sheet (Topic 201): Disclosures about Offsetting Assets and Liabilities (ASU 2011-11) . ASU 2011-11 requires disclosure of information about offsetting and related arrangements to enable users of financial statements to understand the effect or potential effect of netting arrangements on an entity s financial position, including the effect or potential effect of rights of setoff associated with certain financial instruments and derivative instruments. The required disclosures are effective for our annual report for the year ending December 31, 2013 and for interim periods within that year. We have not yet completed our review of the required disclosures; however, we expect the impact on our reporting to be immaterial.

(2) Acquisitions

The ASOP Acquisition

On February 14, 2011, we acquired 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) from ASOP for $200.7 million in cash, subject to purchase price adjustments to reflect an economic effective date of January 1, 2011. As of December 31, 2010, the ASOP Properties had estimated proved reserves of approximately 8.1 Mmboe, of which 84% were oil and 76% were proved developed reserves. The primary factors considered by management in acquiring the ASOP Properties include the belief that the ASOP Acquisition provides an opportunity to significantly increase 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. We financed the ASOP Acquisition with the proceeds from the sale of $210 million in aggregate principal amount of the 8.25% Notes. After deducting the initial purchasers discount and offering expenses, we realized net proceeds of approximately $202 million. See Note 7, Indebtedness for more information regarding our 8.25% Notes.

We have accounted for the ASOP Acquisition using the purchase method of accounting for business combinations, and therefore we have estimated the fair value of the ASOP Properties as of the February 14, 2011 acquisition date. In the estimation of fair value, management uses various valuation methods including (i) comparable company analysis, which estimates the value of the ASOP Properties based on the implied valuations of other similar operations; (ii) comparable asset transaction analysis, which estimates the value of the acquired operations based upon publicly announced transactions of assets with similar characteristics; (iii) comparable merger transaction analysis, which, much like comparable asset transaction analysis, estimates the value of operations based upon publicly announced transactions with similar characteristics, except that merger analysis analyzes public to public merger transactions rather than solely asset transactions; and (iv) discounted cash flow analysis, which estimates the value of the ASOP Properties by determining the present value of estimated future cash flows. The fair value is based on subjective estimates and assumptions, which are inherently subject to significant uncertainties which are beyond our control. These assumptions represent Level 3 inputs, as further discussed in Note 10, Fair Value Measurements.

The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects adjustments to purchase price provided for by the purchase and sale agreement of approximately $3.8 million to reflect an economic effective date of January 1, 2011.

(In thousands)	January 1, 2011
Oil and natural gas properties	$ 221,751
Asset retirement obligations	(24,858)
Net assets acquired	$ 196,893

The Main Pass Acquisition

On November 17, 2011, we acquired certain interests in producing oil and natural gas assets in the shallow-water central Gulf of Mexico shelf (the Main Pass Interests) from Stone Energy Offshore, L.L.C. (the Seller) for $38.6 million in cash, subject to customary adjustments to reflect the 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 ASOP Acquisition, along with other unit interests in the Main Pass complex and an interest in a Main Pass 295 primary term lease. We estimate that the proved reserves as of the November 1, 2011 economic effective date totaled approximately 2.6 Mmboe, all of which were proved developed reserves and approximately 96% of which were oil reserves. We funded the Main Pass Acquisition with cash on hand.

The following allocation of the purchase price as of November 1, 2011 is preliminary and includes estimates. This preliminary allocation is based on information that was available to management at the time these consolidated financial statements were prepared and is subject to revision as management finalizes adjustments to purchase price provided for by the purchase and sale agreement. Accordingly, the allocation may change as additional information becomes available and is assessed by management, and the impact of such changes may be material.

The following table summarizes the estimated values of assets acquired and liabilities assumed to reflect an economic effective date of November 1, 2011.

(In thousands)	November 1, 2011
Oil and natural gas properties	$ 40,157
Asset retirement obligations	(1,577)
Net assets acquired	$ 38,580

Revenues and lease operating expenses attributable to the ASOP Properties and the Main Pass Interests for the year ended December 31, 2011 were $126.0 million and $17.2 million, respectively. We have determined that the presentation of net income attributable to the ASOP Properties and the Main Pass Interests is impracticable due to the integration of the related operations upon acquisition. We incurred fees of approximately $0.5 million related to the ASOP Acquisition and $0.1 million related to the Main Pass Acquisition, which were included in general and administrative expenses in the accompanying consolidated statement of operations for the year ended December 31, 2011.

Pro Forma Information

The following supplemental pro forma information presents consolidated results of operations as if the ASOP Acquisition and Main Pass Acquisition had occurred on January 1, 2010. This supplemental unaudited pro forma information was derived from a) our historical consolidated statements of operations, b) the statements of revenues and direct operating expenses for the ASOP Properties, which were derived from ASOP s historical accounting records and c) the statements of revenues and direct operating expenses for the Main Pass Interests, which were derived from the historical accounting records of Seller. This information does not purport to be indicative of results of operations that would have occurred had the acquisition occurred on January 1, 2010, nor is such information indicative of any expected future results of operations.

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	Year Ended December 31,	
	Pro Forma 2011	Pro Forma 2010
	(in thousands, except per share data)	
Revenue	$ 376,586	$ 344,599
Net income	$ 32,087	$ 6,429
Basic earnings per share	$ 0.80	$ 0.16
Diluted earnings per share	$ 0.80	$ 0.16

(3) Common Stock

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. 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. Through December 31, 2011, we executed trades to repurchase 1,019,000 shares at an aggregate cash purchase price of approximately $12.8 million. Of these repurchases, settlements related to 103,000 shares with an aggregate cash purchase price of approximately $1.5 million occurred in January 2012. The repurchased 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.

In connection with our emergence from Chapter 11 reorganization in September 2009, we converted the Company s 9.75% Senior Unsecured Notes due 2014 (the Fixed Rate Notes), its Senior Floating Rate Notes due 2013 (the Floating Rate Notes and together with the Fixed Rate Notes, the Senior Unsecured Notes) and its 8.75% Senior Notes due 2010 (collectively with the Senior Unsecured Notes, the Predecessor Company Notes) and outstanding Predecessor Company common stock into shares of our new common stock as of the Exit Date. In accordance with the terms of the Plan of Reorganization, the Predecessor Company Notes and related indentures, as well as the Predecessor Company s outstanding common shares, were cancelled. Each holder of these notes received, in exchange for such holder s respective claim (including principal and accrued interest), such holder s pro rata portion of approximately 95% of the common stock in the Successor Company, or 38 million shares. Each holder of the Predecessor Company s common stock received, in full satisfaction of and in exchange for such holder s respective common stock interests, such holder s pro rata portion of approximately 5% of the common stock in the Successor Company, or approximately 2 million shares. The shares of treasury stock held by the Predecessor Company were not allocated any portion of the newly issued common stock. In each case, the common stock of the Successor Company issued pursuant to the Plan of Reorganization is subject to dilution by the issuance of shares of common stock issuable under the Successor Company s 2009 Long-Term Incentive Plan. We reserved up to 1,237,000 shares of common stock for the issuance of restricted shares and option shares under the 2009 Long-Term Incentive Plan. In May 2011, the reserved shares were increased to 2,474,000, with 1,201,707 shares remaining for issuance as of December 31, 2011. See Note 12, Employee Benefit Plans for information regarding the 2009 Long-Term Incentive Plan.

Covenants in certain debt instruments to which we are a party, including our credit facility and the indenture related to our 8.25% Notes, place certain restrictions and conditions on our ability to pay dividends on our common stock.

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(4) Earnings Per Share

The following table sets forth the calculation of basic and diluted weighted average shares outstanding and earnings per share for the indicated periods.

	SUCCESSOR COMPANY			PREDECESSOR COMPANY
	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
Income (numerator):				
Net income (loss)	$ 26,611	$ (8,468)	$ (21,012)	$ (36,114)
Net income attributable to participating securities	(77)			
Net income (loss) basic and diluted	$ 26,534	$ (8,468)	$ (21,012)	$ (36,114)
Weighted average shares (denominator):				
Weighted average shares basic	39,946	40,064	40,020	32,200
Dilutive effect of stock options and unvested restricted shares	104			
Weighted average shares diluted	40,050	40,064	40,020	32,200
Basic income (loss) per share	$ 0.66	$ (0.21)	$ (0.53)	$ (1.12)
Diluted income (loss) per share	$ 0.66	$ (0.21)	$ (0.53)	$ (1.12)

For the year ended December 31, 2011, stock options excluded from the diluted income per share calculation because they were antidilutive for the period totaled approximately 442,155. For the year ended December 31, 2010, for the period from October 1, 2009 through December 31, 2009, and for the period from January 1, 2009 through September 30, 2009, all outstanding stock options and unvested restricted shares were considered antidilutive because we had net losses for those periods.

(5) Property and Equipment

The following table summarizes our property and equipment at December 31, 2011 and 2010.

	2011	2010
	(In thousands)	
Proved oil and natural gas properties	$ 1,049,140	$ 687,759
Unproved oil and natural gas properties	29,382	29,230
Other	3,726	2,158
	$ 1,082,248	$ 719,147

Substantially all of our oil and natural gas properties serve as collateral under our credit facility.

We recognized impairments of $32.5 million, $26.1 million, $8.5 million and $8.1 million in the year ended December 31, 2011, the year ended December 31, 2010, the period from October 1, 2009 through December 31, 2009 and the period from January 1, 2009 through September 30, 2009, respectively.

Impairments for the year ended December 31, 2011 were primarily related to our 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.

Impairments for the year ended December 31, 2010 were primarily related to the decline in our estimate of future natural gas prices as of September 30, 2010 as compared to June 30, 2010 affecting two producing fields, including our deepwater producing well, and to reservoir performance of one of these fields and one additional producing field. These producing 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 during the year ended December 31, 2010.

Impairments recorded by the Successor Company in the quarter ended December 31, 2009 were primarily related to two wells in our Gulf of Mexico shelf area, one of which was unsuccessfully recompleted in 2010; the other was determined to be mechanically unable to produce a behind-pipe reservoir. Impairments of the Predecessor Company for the period from January 1, 2009 through September 30, 2009 were primarily related to two producing fields which were determined to have future net cash flows less than their carrying values due to commodity price declines and reservoir performance.

At December 31, 2011 and 2010, we did not have any projects that were suspended for a period greater than one year.

(6) Asset Retirement Obligations

We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred, along with a corresponding increase in the carrying amount of the related long-lived asset. The following table reconciles the beginning and ending aggregate recorded amount of our asset retirement obligations.

	Years Ended December 31,	
	2011	2010
	(in thousands)	
Beginning of period total	$ 71,583	$ 69,980
Accretion expense	15,942	12,845
Revisions	17,595	4,766
Liabilities assumed in acquisitions	26,435	
Liabilities incurred	157	128
Liabilities settled	(32,365)	(16,136)
End of period total	99,347	71,583
Less: End of period current portion	(25,578)	(16,902)
End of the period noncurrent portion	$ 73,769	$ 54,681

We increased our cost estimates on a portion of our asset retirement obligations to reflect higher overall prices for services, material and equipment. Primarily due to changes in estimated reserve lives, the timing of a portion of our asset retirement obligations was revised in the fourth quarter of 2011 leading to a reduction of the present value of those obligations, partially offsetting the impact of the cost increases.

(7) Indebtedness

The following table sets forth our indebtedness.

	December 31,	
(In thousands)	2011	2010
8.25% Senior Notes, face amount of $210.0 million, interest rate of 8.25% payable semi-annually, in arrears on February 15 and August 15 of each year, mature February 15, 2018	$ 204,390	$
Senior Credit Facility, interest rate based on base rate or LIBOR plus a floating spread, maturity date February 14, 2015		
Total indebtedness	204,390	
Current portion of indebtedness		
Noncurrent portion of indebtedness	$ 204,390	$

In connection with the ASOP Acquisition (see Note 2), on February 14, 2011, we issued $210.0 million in aggregate principal amount of our 8.25% Notes due 2018. Furthermore, our credit facility existing on that date was terminated and replaced with a new credit facility. The termination of our prior credit facility during the year ended December 31, 2011 resulted 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.

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The 8.25% Notes

On February 14, 2011, we issued the $210.0 million in aggregate principal amount of our 8.25% Notes under an Indenture, dated as of February 14, 2011 (the Indenture). As described in Note 2, Acquisitions, we used the net proceeds from the offering of the 8.25% 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. The 8.25% 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 15 and August 15 of each year, commencing on August 15, 2011. The 8.25% 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% Notes will mature on February 15, 2018.

The 8.25% 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. In connection with the execution of the Indenture, we also entered into a registration rights agreement, dated as of February 14, 2011 (the Registration Rights Agreement). Under the Registration Rights Agreement, on July 14, 2011, we and our guarantor subsidiaries (the Guarantors) filed a registration statement with the SEC, which was declared effective on July 26, 2011, offering to exchange a new series of freely tradable notes having substantially identical terms as the 8.25% Notes (Exchange Notes) for the 8.25% Notes. Pursuant to this offering, 100% in aggregate principal amount of the 8.25% Notes was exchanged for the Exchange Notes, effective as of August 29, 2011.

On or after February 15, 2015, we may on any one or more occasions redeem all or a part of the 8.25% Notes upon not less than 30 nor more than 60 days notice, at the redemption prices (expressed as percentages of principal amount) set forth below, plus accrued and unpaid interest on the 8.25% Notes redeemed, to the applicable redemption date, if redeemed during the twelve-month period beginning on February 15th of the years indicated below, subject to the rights of holders of the 8.25% Notes on the relevant record date to receive interest on the relevant interest payment date:

Year	Percentage
2015	104.125%
2016	102.063%
2017 and thereafter	100.000%

Any such redemption and notice may, in our discretion, be subject to the satisfaction of one or more conditions precedent, including but not limited to, the occurrence of a change of control. Unless we default in the payment of the redemption price, interest will cease to accrue on the 8.25% Notes or portions thereof called for redemption on the applicable redemption date.

At any time prior to February 15, 2014, we may, at our option, on any one or more occasions redeem with the net cash proceeds of certain equity offerings up to 35% of the aggregate principal amount of outstanding 8.25% Notes (which amount includes additional notes issued under the Indenture), upon not less than 30 nor more than 60 days prior notice, at a redemption price equal to 108.250% of the principal amount of the notes redeemed, plus accrued and unpaid interest to the redemption date, provided that: (1) at least 65% of the aggregate principal amount of the 8.25% Notes issued under the Indenture (which amount includes additional notes issued under the Indenture) remains outstanding immediately after the occurrence of such redemption; and (2) the redemption occurs within 90 days of the date of the closing of such equity offering. This option to redeem up to 35% of the aggregate principal amount of outstanding 8.25% Notes with the net cash proceeds of certain equity offerings is considered an embedded derivative. We estimate that the fair value of this option at December 31, 2011 is not material. In addition, we may, at our option, on any one or more occasions redeem all or a part of the 8.25% Notes prior to February 15, 2015 at a redemption price equal to 100% of the principal amount of the 8.25% Notes redeemed plus a make-whole premium as of, and accrued and unpaid interest to the redemption date.

If we experience a change of control (as defined in the Indenture), each holder of the 8.25% Notes will have the right to require us to repurchase all or any part (equal to $2,000 or an integral multiple of $1,000 in excess thereof) of the 8.25% Notes at a price in cash equal to 101% of the aggregate principal amount of the 8.25% Notes repurchased, plus accrued and unpaid interest to the date of repurchase. If we engage in certain asset sales, within 360 days of such sale, we generally must use the net cash proceeds from such sales to repay outstanding senior secured debt (other than intercompany debt or any debt owed to an affiliate), to acquire all or substantially all of the assets, properties or capital stock of one or more companies in our industry, to make capital expenditures or to invest in our business. When any such net proceeds that are not so applied or invested exceed $20.0 million, we must make an offer to purchase the 8.25% Notes and other pari passu debt that is subject to similar asset sale provisions in an aggregate principal amount equal to the excess net cash proceeds. The purchase price of each 8.25% Note (or other pari passu debt) so purchased will be 100% of its principal amount, plus accrued and unpaid interest to the repurchase date, and will be payable in cash.

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The Indenture, among other things, limits our ability to: (i) declare or pay dividends, redeem subordinated debt or make other restricted payments; (ii) incur or guarantee additional debt or issue preferred stock; (iii) create or incur liens; (iv) incur dividend or other payment restrictions affecting restricted subsidiaries; (v) consummate a merger, consolidation or sale of all or substantially all of our assets; (vi) enter into sale-leaseback transactions, (vii) enter into transactions with affiliates; (viii) transfer or sell assets; (ix) engage in business other than our current business and reasonably related extensions thereof; or (x) issue or sell capital stock of certain subsidiaries. These covenants are subject to a number of important exceptions and qualifications set forth in the Indenture.

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 (Senior Credit Facility). Upon the closing of our Senior Credit Facility, our then existing credit facility was terminated. The terms of our Senior Credit Facility establish a revolving credit facility with a four-year term that may be used for revolving credit loans and letters of credit up to an aggregate principal amount of $250.0 million, subject to an initial borrowing base of $150.0 million. The maximum amount of letters of credit that may be outstanding at any one time is $20.0 million, and the amount available under the revolving credit facility is limited by the borrowing base. With the consent of the agent, we also have the ability to increase the aggregate commitments under the Senior Credit Facility by up to $100.0 million to the extent that existing and/or future lenders provide additional commitments. The determination of our borrowing base under our Senior Credit Facility is based on our proved reserves, at the sole discretion of the lenders. Scheduled borrowing base redeterminations will be made on a semi-annual basis on May 1st and November 1st of each year. In November 2011, we completed our semi-annual redetermination and our borrowing base was increased to $200.0 million. We had no amounts drawn under our Senior Credit Facility at December 31, 2011.

The interest rate spread on loans and letters of credit under our Senior Credit Facility is based on the level of utilization and range from a base rate plus a margin of 1.00% to 2.00% for base rate borrowings and LIBOR plus a margin of 2.00% to 3.00% for LIBOR borrowings. A commitment fee of 0.5% is payable on the unused portion of the borrowing base. Interest on our base rate borrowings is payable quarterly, in arrears, and interest on our LIBOR borrowings is payable on the last day of each relevant interest period, except that in the case of any interest period that is longer than three months, interest is payable on each successive date three months after the first day of such interest period.

Our Senior Credit Facility contains customary covenants, default provisions and collateral requirements. As described in the agreement underlying our Senior Credit facility, we must maintain, for each period for which a covenant certification is required, (a) a minimum current ratio (as defined in the agreement for our Senior Credit Facility) of 1.0 to 1.0, (b) a minimum EBITDAX (as defined in the agreement for our Senior Credit Facility) to interest expense coverage ratio of 2.5 to 1.0 and (c) a maximum total debt to EBITDAX ratio of 3.5 to 1.0. We are also required to maintain a commodities hedging program that is in compliance with the requirements set forth in our Senior Credit Facility. Our Senior Credit Facility also places restrictions on the maximum estimated future production volumes that can be subject to commodity derivative instruments.

Our obligations under our Senior Credit Facility, as well as any hedging contracts and treasury management agreements with the lenders or affiliates of lenders, are guaranteed by our material domestic subsidiaries and secured by a pledge of 100% of the stock of each material domestic subsidiary and 66 $^{2}/_{3}$% of each of their foreign material subsidiaries and a first priority lien on substantially all of our and our material subsidiaries assets, including our real property assets and the oil and gas properties to which 85% of the present value of our proved reserves is attributable.

Credit Facility at December 31, 2010

On June 16, 2010, we entered into an amendment (the First Amendment) to our prior credit facility dated as of September 21, 2009, (together with the First Amendment, the Amended Prior Credit Facility) with General Electric Capital Corporation, as administrative agent (the Agent), and the lender parties thereto (the Lenders). Upon its effectiveness on June 28, 2010, the Amended Prior Credit Facility established a $70.0 million borrowing base consisting of (a) a new $25.0 million term loan payable, with interest, in six equal monthly installments of principal from July 28, 2010 to December 28, 2010 and (b) a revolving credit facility with a three-year term that could be used for revolving credit loans and letters of credit up to an initial maximum principal amount of $45.0 million. The interest rate spread on loans and letters of credit under the Amended Prior Credit Facility was based on the level of utilization and ranged from 3.75% to 4.25% for base rate borrowings and 4.75% to 5.25% for LIBOR borrowings. The First Amendment contained the Lenders consent for us to redeem all outstanding principal and pay all accrued interest on our 20% Senior Subordinated Secured PIK Notes due 2014 in an aggregate principal amount of $61.1 million (the PIK Notes), which redemption occurred on June 28, 2010 and was a condition to the effectiveness of the First Amendment. On December 28, 2010, we repaid in full all outstanding borrowings under the term loan component of our Amended Prior Credit Facility and had no borrowings outstanding on the revolver component at December 31, 2010.

The First Amendment did not make any material changes to the covenants, default provisions or collateral requirements under the prior credit facility. Our obligations under the Amended Prior Credit Facility and under derivative contracts were guaranteed by our material subsidiaries and secured by our real property assets and the oil and natural gas properties to which 90% of the present value of our proved reserves was attributable.

The documentation for our Amended Prior Credit Facility provided security for our obligations arising from derivative contracts with lenders under the Prior Credit Facility. On October 29, 2010, we entered into a novation agreement under which, effective October 1, 2010, we novated certain of our derivative contracts. The novation agreement effectively transferred all the rights, liabilities, duties and obligations of a certain derivative counterparty under those contracts to a new counterparty.

At December 31, 2010, our borrowing base was $45.0 million under the Amended Prior Credit Facility. The maximum amount of letters of credit that could be outstanding at any one time was $20.0 million, and the amount available under the revolving credit facility was limited by the borrowing base. The borrowing base was subject to semi-annual redeterminations based on the proved reserves of the oil and natural gas properties that served as collateral for the Amended Prior Credit Facility. In January 2011, our borrowing base had been reaffirmed at $45.0 million.

Prior Credit Facility and PIK Notes

On the Exit Date, we consummated certain transactions contemplated by the Plan of Reorganization, including entering into a senior secured credit facility consisting of a $125.0 million revolving credit facility with an initial borrowing base of $45 million (the Prior Revolver) and a $25.0 million one-year amortizing term loan facility (together with the Revolver, the Prior Credit Facility). We also issued 20% Senior Subordinated Secured PIK Notes due 2014 in an aggregate principal amount of $61.1 million pursuant to an indenture dated September 21, 2009. The PIK Notes were issued with original issue discount, and the note proceeds after this discount were $55.0 million.

On June 28, 2010, we redeemed all outstanding principal and paid all accrued interest on the PIK Notes. The redemption price of the PIK Notes was 100% of the outstanding aggregate principal amount. In connection with the redemption, we paid a total of $70.9 million of principal and accrued interest. We recorded a loss on the redemption of $5.6 million representing the total of the unamortized original issue discount and unamortized deferred financing costs associated with the PIK Notes.

The PIK Notes allowed, or required, as specified in the indenture, for payment of interest in-kind in the form of newly issued notes having the same terms as the PIK Notes. Interest on the PIK Notes and newly issued PIK Notes issued for payment of periodic interest was payable in additional PIK Notes or in cash subject to limitations described as follows and in the indenture. Until the first interest payment date that would occur 91 days after the repayment in full of all amounts outstanding under the Prior Credit Facility and the termination of the Lenders commitments under the Prior Credit Facility (such date being, the Credit Facility Termination Date), interest on the PIK Notes was payable in-kind, semi-annually in arrears on January 1 and July 1 of each year, beginning on January 1, 2010. At December 31, 2009, our total indebtedness related to the PIK Notes included $3.4 million of accrued interest in-kind for which new notes were issued on January 1, 2010. After the Credit Facility Termination Date, interest on the original PIK Notes and any additional PIK Notes issued for in-kind interest payments, would be payable quarterly in cash in arrears on January 1, April 1, July 1 and October 1 of each year. All of the PIK Notes would have matured on September 21, 2014 along with all accrued but unpaid interest and the outstanding PIK Note principal balances.

The PIK Notes were (a) subordinated in right of payment to the Prior Credit Facility, (b) guaranteed by our material subsidiaries and (c) (i) prior to the Credit Facility Termination Date, secured by our real property assets and the oil and gas properties to which 90% of the present value of our proved reserves was attributable (the Collateral) or (ii) after the Credit Facility Termination Date, secured by the Collateral plus certain additional real property collateral as may be required under the indenture. The security interests granted for the benefit of the holders of the PIK Notes were subordinated to those granted in favor of the Lenders. The indenture related to the PIK Notes imposed customary negative covenants, which were based on such covenants contained in the Prior Credit Facility, and contained customary events of default, except that there were no financial performance covenants contained in the indenture.

Predecessor Indebtedness

In April 2007, the Predecessor Company refinanced an existing bank credit facility with a credit agreement, which had availability and a borrowing base of $200.0 million and was secured by substantially all of our assets (the Pre-Reorganization Credit Agreement). The borrowing base under the Pre-Reorganization Credit Agreement was subject to redetermination based on the proved reserves of the oil and natural gas properties that served as collateral as set out in the reserve report delivered to the banks in April and October each year. In November 2008, the Pre-Reorganization Credit Agreement was redetermined with a borrowing base of $150.0 million. At December 31, 2008, we had $43 million outstanding under the Pre-Reorganization Credit Agreement. In March 2009, the Pre-Reorganization Credit Agreement was redetermined with a new borrowing base of $45 million. The Predecessor Company had $83 million outstanding under the Pre-Reorganization Credit Agreement, resulting in a deficiency of $38 million and a demand for repayment of the borrowing base deficiency.

While we were not in default under our Pre-Reorganization Credit Agreement as of December 31, 2008, we subsequently failed to timely satisfy a number of Pre-Reorganization Credit Agreement covenants, including those requiring the delivery of our December 31, 2008 debt compliance certificate in April 2009 and providing our December 31, 2008 financial results at that time. On September 21, 2009, outstanding borrowings under the Pre-Reorganization Credit Agreement of $83 million were repaid using proceeds from the Prior Credit Facility and the PIK Notes.

As described in Note 17, Reorganization and Fresh-Start Accounting, the Predecessor Company Notes and the related indentures were cancelled in connection with the reorganization, resulting in a loss on debt discharge of $2.7 million during the period from January 1, 2009 through September 30, 2009. In addition, the outstanding borrowings under the Pre-Reorganization Credit Agreement and related accrued interest were repaid.

(8) Concentrations

Significant Customers

We had oil and natural gas sales to three customers accounting for 51%, 17% and 12%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2011.We had oil and natural gas sales to three customers accounting for 42%, 26% and 11%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2010. We had oil and natural gas sales to three customers accounting for 36%, 19% and 14%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the period from October 1, 2009 through December 31, 2009. We had oil and natural gas sales to three customers accounting for 30%, 27% and 21%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the period from January 1, 2009 through September 30, 2009.

Tropical Weather

During the periods from October 1, 2009 through December 31, 2009 and from January 1, 2009 through September 30, 2009, we recorded reductions to lease operating expenses for property damage claims totaling approximately $4.1 million and $1.4 million, respectively, all of which was recorded in receivables from insurance at December 31, 2009. In order to mitigate the higher cost of insurance coverages in 2009, we negotiated higher deductibles for property damage due to named windstorms (such as hurricanes) and significantly lower aggregates for property damage due to named windstorms. Currently, we have an offshore property physical damage policy with a deductible applicable to named windstorm events of $20.0 million per occurrence and an aggregate annual named windstorm limit of $90.0 million of which we self-insure approximately 9%. Due to limited availability of insurance coverage at commercially acceptable rates, we no longer maintain business interruption insurance.

In late August and early September 2008 Hurricanes Gustav and Ike traversed the Gulf of Mexico and adjacent land areas. As a result of these two hurricanes, nearly all of our production was shut-in at one time or another during the third and fourth quarters of 2008. For these occurrences, we maintained business interruption insurance on a portion of our lost revenue on our South Timbalier 41, 42 and 46 properties. Recovery of lost revenue from these properties began accruing during the fourth quarter of 2008 when the no claim period provided for under the policy elapsed. Through December 31, 2008, the total business interruption claim on these fields was $4.2 million, all of which was collected in 2009.

(9) Derivative Instruments and Hedging Activities

We enter into derivative instruments to reduce exposure to fluctuations in the price of oil and natural gas for a portion of our production. Our fixed-price swaps fix the sales price for a limited amount of our production and, for the contracted volumes, eliminate our ability to benefit from increases in the sales price of the production. Our collars limit our exposure to declines in the sales price of oil while giving us the ability to benefit from increases in the sales price of oil to a certain level for a limited amount of our production. Derivative instruments are carried at their fair value on the consolidated balance sheets as Fair value of commodity derivative instruments and all unrealized and realized gains and losses are recorded in Gain (loss) on derivative instruments in Other income (expense) in the consolidated statements of operations. See Note 10 for information regarding fair values of our derivative instruments.

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The following table sets forth our derivative instruments outstanding as of December 31, 2011.

Oil Contracts

	Fixed-Price Swaps		
Remaining Contract Term	Daily Average Volume (Bbls)	Volume (Bbls)	Average Swap Price ($/Bbl)
January 2012 July 2012	3,880	826,500	$ 100.44
August 2012 November 2012	2,721	332,000	$ 103.76
December 2012	3,161	98,000	$ 102.47
January 2013 July 2013	2,471	523,900	$ 97.84
August 2013 November 2013	426	52,000	$ 94.18
December 2013	806	25,000	$ 93.98

	Collars		
Remaining Contract Term	Daily Average Volume (Bbls)	Volume (Bbls)	Average Strike Price ($/Bbl)
January 2012 July 2012	1,000	213,000	$ 87.50/123.18
August 2012 November 2012	1,000	122,000	$ 87.50/123.18
December 2012	1,000	31,000	$ 87.50/123.18

The following table presents information about the components of gain (loss) on derivative instruments.

(In thousands)	Successor Company Year Ended December 31, 2011	Successor Company Year Ended December 31, 2010	Successor Company Period from October 1, 2009 through December 31, 2009	Predecessor Company Period from January 1, 2009 through September 30, 2009
Derivative contracts:				
Unrealized gain (loss) due to change in fair market value	$ 11,475	$ 3,500	$ (21,739)	$
Realized gain (loss) on settlement	(17,345)	(8,365)	(966)	2,728
Total gain (loss) on derivative instruments	$ (5,870)	$ (4,865)	$ (22,705)	$ 2,728

During the period from January 1, 2009 through September 30, 2009, we had agreed to termination of our derivative contracts as requested by our lenders or as required by the terms of our agreements with them.

(10) Fair Value Measurements

ASC Topic 820, Fair Value Measurements and Disclosures, establishes a fair value hierarchy with three levels based on the reliability of the inputs used to determine fair value. These levels include: Level 1, defined as inputs such as unadjusted quoted prices in active markets for identical assets and liabilities; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs for use when little or no market data exists, therefore requiring an entity to develop its own assumptions.

As of December 31, 2011 and 2010, we held certain financial assets and liabilities that are required to be measured at fair value on a recurring basis, primarily our commodity derivative instruments. At December 31, 2011 and 2010, the fair values of derivative instruments were measured using price inputs published by NYMEX and IntercontinentalExchange, Inc., or ICE. These price inputs are quoted prices for assets and liabilities similar to those held by us and meet the definition of Level 2 inputs within the fair value hierarchy. At December 31, 2011, the carrying amounts and fair values of our derivative instruments are reported as assets totaling $0.6 million and liabilities totaling $1.2 million. At December 31, 2010, the carrying amounts and fair values of our derivative instruments are reported as assets totaling $0.2 million and liabilities totaling $12.3 million.

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As of December 31, 2011, the carrying amount of our 8.25% Notes is $204.4 million, which reflects the $210.0 million face amount, net of the unamortized amount of initial purchasers discount of $5.6 million. We estimate the fair value of the 8.25% Notes at approximately $202.7 million, based on quoted prices, which are Level 1 inputs within the fair value hierarchy.

We evaluate our capitalized costs of proved oil and natural gas properties for potential impairment when circumstances indicate that the carrying values may not be recoverable. 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 (generally analogous to a field or a lease). 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. The inputs used to estimate the fair value of our oil and natural gas properties meet the definition of Level 3 inputs within the fair value hierarchy. Impairments for the year ended December 31, 2011 were primarily related to our 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. Impairments for the year ended December 31, 2010 were primarily related to the decline in our estimate of future natural gas prices as of September 30, 2010 as compared to June 30, 2010 affecting two producing fields, including our deepwater producing well, and to reservoir performance of one of these fields and one additional producing field. These producing 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 during the year ended December 31, 2010.

As addressed in Note 17, Reorganization and Fresh-Start Accounting, we applied fair value concepts in allocating the reorganization value of the Company to our assets and liabilities as a result of the reorganization and application of ASC 852. The inputs to the fair values of our more significant assets and liabilities are addressed in Note 17.

(11) Income Taxes

The following table sets forth the components of our income tax benefit (expense).

	Successor Company Year Ended December 31, 2011	Successor Company Year Ended December 31, 2010	Successor Company October 1, 2009 through December 31, 2009	Predecessor Company January 1, 2009 through September 30, 2009
	(In thousands)			
Current:				
Federal	$	$	$	$
State				
	$	$	$	$
Deferred:				
Federal	$ (14,468)	$ 4,248	$ 11,076	$
State	(354)	161	324	
	$ (14,822)	$ 4,409	$ 11,400	$
Total:				
Federal	$ (14,468)	$ 4,248	$ 11,076	$
State	(354)	161	324	
	$ (14,822)	$ 4,409	$ 11,400	$

The following table reconciles the expected statutory federal income tax rate to our effective income tax rate.

	Percentage of Pretax Earnings			
	Successor Company Year Ended December 31, 2011	Successor Company Year Ended December 31, 2010	Successor Company October 1, 2009 through December 31, 2009	Predecessor Company January 1, 2009 through September 30, 2009
Expected statutory federal income tax rate	35.0%	35.0%	35.0%	35.0%
State taxes	2.3	2.6	1.0	1.0
Valuation allowance				(41.0)
State tax rate changes	(1.7)	(3.6)		
Statutory depletion	(1.0)	3.4		
Other	1.2	(3.2)	(0.8)	5.0
	35.8%	34.2%	35.2%	0%

The following table sets forth the tax effects of temporary differences that give rise to significant portions of the current tax asset and net deferred tax liability at December 31, 2011 and 2010.

	2011	2010
	(In thousands)	
Current deferred tax assets (liabilities):		
Fair value of commodity derivative instruments	$ 175	$ 70
Prepaid assets	(1,435)	(1,995)
Accruals and other	(1,563)	4,618
Net current deferred tax asset (liability)	$ (2,823)	$ 2,693
Non-current deferred tax assets:		
Restricted stock awards and options	$ 1,272	$ 558
Federal and state net operating loss carryforwards	60,266	47,706
Fair market value of commodity derivative instruments	71	
Percentage depletion carryforward	4,105	3,719
Other	943	5,810
Non-current deferred tax asset	66,657	57,793
Non-current deferred tax liabilities:		
Property, plant and equipment, principally due to differences in depreciation	(98,432)	(80,262)
Net non-current deferred tax liability	$ (31,775)	$ (22,469)

As a result of our reorganization under Chapter 11 in 2009 as described in Note 17, Reorganization and Fresh-Start Accounting, the income from the discharge of indebtedness, represented for tax purposes as the excess of the principal and accrued interest on the debt discharged over the fair value of the stock of the reorganized company received in exchange for the discharged obligations, as defined by Internal Revenue Code (the IRC) Section 108 (IRC 108), reduced our net operating loss carryforwards (NOLs) by $97 million (Tax Attribute Reduction). Our remaining NOLs as of December 31, 2011 were approximately $160 million.

Ownership changes, as defined in IRC Section 382, limit the amount of NOLs that can be utilized annually to offset future taxable income and reduce our tax liability (Section 382 Limitation). In 2009, as part of our Chapter 11 reorganization, we had an ownership change which resulted in a Section 382 Limitation on the amount of NOLs available annually for use. Unused annual limited NOLs (those NOLs in existence immediately after the application of IRC 108) totaled $133 million. The annual limitation is approximately $21 million per year beginning in 2010 and, if unused, can be carried over and aggregated with limited NOLs in future years subject to the ultimate expiration of the NOLs. We have not used any limited NOLs since the reorganization. The amount of limited NOLs available for our 2011 federal tax return is approximately $48 million. We believe that we will be able to utilize all of our federal NOLs prior to their expiration.

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Prior to December 31, 2009, our net deferred tax position had changed from a net deferred tax liability position to a net deferred tax asset position, before consideration of the valuation allowance. We were not able to conclude that it was more likely than not that our net deferred tax assets would be realized through future earnings and reversal of taxable temporary differences, primarily due to the existence of cumulative book losses for the three year period ended December 31, 2008. As a result, we had previously provided a valuation allowance of $7.5 million as of December 31, 2008, which reduced our net deferred tax asset to zero. The Tax Attribute Reduction changed our net deferred tax position, before consideration of the valuation allowance, from a net deferred tax asset to a net deferred tax liability, which eliminated the need for the valuation allowance; thus, we reversed all of the previously established valuation allowance as of December 31, 2009.

Our federal NOLs of approximately $160 million as of December 31, 2011 are available to reduce future federal taxable income subject to the limitations and estimates described above and the application of the tax rules and regulations. The NOLs begin expiring in the years 2025 through 2031.

As of January 1, 2011, our 2008-2010 income tax years remain subject to examination by the Internal Revenue Service. In addition, our 2007-2010 state income/franchise tax years remain subject to examination by the States of Louisiana and Texas. As of the date of these financial statements, our 2011 U.S. federal and state income tax returns have not been filed, although management expects to file such returns in a timely manner during 2012. We have no material uncertain tax positions as of December 31, 2011.

(12) Employee Benefit Plans

Share-Based Compensation Plans

In September 2009 the Board of Directors of the Successor Company adopted the Energy Partners, Ltd. 2009 Long Term Incentive Plan (the 2009 LTIP). The purpose of the 2009 LTIP is to provide a means to enhance our profitable growth by attracting and retaining directors, officers and other key employees through affording such individuals a means to acquire and maintain stock ownership or awards the value of which is tied to the performance of our common stock. All directors, officers and other key employees providing services to the Company are potentially eligible to participate in the 2009 LTIP. The 2009 LTIP provides for grants of (i) incentive stock options qualified as such under income tax rules and regulations, (ii) stock options that do not qualify as incentive stock options, (iii) restricted stock awards, (iv) restricted stock units, (v) stock appreciation rights, (vi) bonus stock and awards in lieu of Company obligations, (vii) dividend equivalents in connection with other awards, (viii) deferred shares, (ix) performance units or shares, or (x) any combination of such awards (collectively referred to as Awards). The 2009 LTIP is administered by a committee of our Board of Directors.

The maximum aggregate number of shares of our common stock that may be issued pursuant to any and all Awards under the 2009 LTIP is limited to 2,474,000 shares, subject to adjustment due to recapitalization or reorganization, or related to forfeitures or the expiration of Awards, as provided under the 2009 LTIP. As of December 31, 2011, 1,201,707 shares remained available for future grants.

Without stockholder or participant approval, the Board of Directors may amend, alter, suspend, discontinue or terminate the 2009 LTIP or the Committee s authority to grant Awards under the 2009 LTIP, except that any amendment or alteration of the 2009 LTIP, including any increase in any share limitation, shall be subject to the approval of the stockholders not later than the next annual meeting if stockholder approval is required by any state or federal law or regulation or the rules of any stock exchange or automated quotation system on which the common stock may then be listed or quoted.

The 2009 LTIP provides for the grant of stock options for which the exercise price, set at the time of the grant, will not be less than the fair market value per share at the date of grant. Our outstanding stock options generally have a term of 10 years and vest ratably on an annual basis over a three-year period from the date of grant, other than the stock option grant to our chief executive officer described in the following paragraph.

Pursuant to an employment agreement and the 2009 LTIP, on September 30, 2009, our new chief executive officer was granted an option to purchase 68,116 shares of Successor Company common stock, which was memorialized in an option award agreement dated as of October 1, 2009 (the Option Agreement). The terms of the Option Agreement provide for an exercise price equal to $10.00 per share. The closing price of our common stock on the NYSE on September 30, 2009 was $7.46 per share. The option vests ratably on a monthly basis over a 36-month period from the date of grant; provided, however, that the vesting for the first six months of the vesting period (the Initial Period) is deferred until the end of the Initial Period and any remaining unvested portion vests ratably on a monthly basis over the remainder of the 36-month vesting period, subject to the executive remaining continuously employed. Vested stock options under the Option Agreement expire 30 months following the applicable vesting date of such stock options. Upon a change in control as defined in the 2009 LTIP, all remaining unvested stock options under the Option Agreement automatically vest and remain exercisable for a period of not less than 30 months following the change in control.

Pursuant to the 2009 LTIP, on the date of the 2011 Annual Meeting of Stockholders, the five members of the Board of Directors were awarded, in the aggregate, a total of 31,405 shares of restricted stock, of which one-half vested immediately and one-half will vest on the day immediately preceding the date of the 2012 Annual Meeting of Stockholders. Pursuant to the 2009 LTIP, on the date of the 2010 Annual Meeting of Stockholders, the five members of the Board of Directors were awarded, in the aggregate, a total of 42,735 shares of restricted stock, of which one-half vested immediately and one-half will vest on the day immediately preceding the date of the 2011 Annual Meeting of Stockholders. In connection with the appointment of the five members of the Board of Directors of the Successor Company and pursuant to the 2009 LTIP, the five directors were awarded, in the aggregate, a total of 43,460 shares of restricted stock, of which one-half vested immediately and one-half vested on the day immediately preceding the date of the 2010 Annual Meeting of Stockholders. Pursuant to elections applicable to the 2010 award made by two directors and applicable to the 2009 award made by one director, the receipt of such stock awards are deferred until such directors cease to serve on our Board of Directors.

Prior to the reorganization, the Predecessor Company had two share-based compensation plans, which are more fully described below. Pursuant to the Plan of Reorganization, all stock option or other equity awards outstanding under these plans became fully vested and were deemed exercised or were cancelled. The number of shares of Predecessor Company common stock that were issued as a result of accelerated vesting of prior restricted stock grants totaled 147,372 shares, which shares were converted into 9,103 shares of Successor Company common stock upon emergence from Chapter 11 reorganization. All Predecessor Company stock and incentive plans for employees were deemed cancelled under the Plan of Reorganization.

The 2006 Long Term Stock Incentive Plan provided for the grant of stock options for which the exercise price, set at the time of the grant, was not less than the fair market value per share at the date of grant. The outstanding options had a term of 10 years and generally vested over three years with grants to a limited group of people that cliff vested at the end of five years.

The Amended and Restated 2000 Stock Incentive Plan for Non-Employee Directors (the Director Plan) was adopted by the Board of Directors in March 2005 and approved by our stockholders in May 2005. The Director Plan permitted the use of restricted share units in addition to stock options to provide flexibility to adjust grants to maintain a competitive equity component for non-employee directors. The option exercise price for an option granted under the Director Plan was the fair market value of the shares covered by the option at the time the option was granted. Options became fully exercisable on the first anniversary of the date of the grant. Prior to the one-year anniversary, the options were exercisable as to a number of shares covered by the option determined by pro-rating the number of shares covered by the option based on the number of days elapsed since the date of the grant. Any portion of an option that had not become exercisable prior to the cessation of the optionee s service as a director for any reason would not thereafter become exercisable. Each option was to expire on the earlier of (1) 10 years from the date of the granting thereof, or (2) 36 months after the date the optionee ceased to be a director of the Company for any reason. Each restricted share unit represented the right to receive one share of common stock upon the earlier to occur of: (1) the cessation of the eligible director s service as a director of the Company for any reason, or (2) the occurrence of a change of control of the Company. An eligible director became 100% vested in a grant of restricted share units on the first anniversary of the date of grant.

The following table sets forth our stock option activity for the year ended December 31, 2011.

	Options	Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contractual Terms (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding on December 31, 2010	488,616	$ 10.49		
Granted	506,230	15.44		
Exercised	(13,333)	8.90		
Forfeited/Cancelled	(47,500)	13.31		
Outstanding on December 31, 2011	934,013	$ 13.05	8.4	$ 2,015
Exercisable on December 31, 2011	167,703	$ 10.47	6.7	$ 693

The fair value of each stock option award was estimated on the date of grant using the Black-Scholes option valuation model using the weighted average assumptions in the table below for the years ended December 31, 2011 and 2010 and for the period from January 1, 2009 through September 30, 2009. No stock option awards were granted during the period from October 1, 2009 through December 31, 2009.

	Year Ended December 31, 2011	Year Ended December 31, 2010	January 1, 2009 through September 30, 2009
Black-Scholes option pricing model assumptions:			
Risk free interest rate	1.9%	2.9%	1.9%
Expected life (years)	6.0	6.0	4.0
Expected volatility	53%	50%	52%
Dividend yield			

Expected volatility is generally based on the historical volatility of our stock over the period of time equivalent to the expected term of the options granted. As a result of our reorganization for purposes of determining expected volatility in 2011, 2010 and 2009, we included consideration of the historical volatility of the share prices of our peers over the relevant time periods in addition to our historical volatility before, during and after our reorganization. We disregarded our share price for the periods during which our stock price was impacted by factors leading up to the Chapter 11 filing and during the period of the Chapter 11 reorganization proceedings because we do not expect these events to reoccur during the expected term of the options. The expected term of options granted is generally derived from historical exercise patterns over a period of time, with consideration of expected term of unvested options. However, because the Successor Company does not have sufficient historical stock option exercise experience upon which to base an estimate of expected term, we used the simplified method for estimating expected term in 2011 and 2010. In 2009, due to the unique vesting schedule of the option award to our new chief executive officer during 2009, we based the expected term assumption for that option award on the weighted average contractual term of the option shares, taking into account the vesting schedule and other factors, including expected exercise and post-vesting employment termination behavior. The risk-free interest rate is based on the interest rate on constant maturity bonds published by the Federal Reserve with a maturity commensurate with the expected term of the options granted.

The weighted-average grant-date fair value of stock options granted during the year ended December 31, 2011, the year ended December 31, 2010 and the period from January 1, 2009 through September 30, 2009 was $7.97, $5.32 and $2.48, respectively. The aggregate intrinsic value (the amount by which the market price of the stock on the date of exercise exceeded the market price of the stock on the date of grant) of stock options exercised during the year ended December 31, 2011 was $0.1 million. No stock options were exercised during the year ended December 31, 2010, the period from October 1, 2009 through December 31, 2009 or the period from January 1, 2009 through September 30, 2009.

The following table sets forth the activity related to our non-vested share awards for the year ended December 31, 2011.

	Shares	Weighted-Average Grant-Date Fair Value
Non-vested share awards outstanding at December 31, 2010	21,370	$ 11.70
Granted	208,934	15.34
Vested	(38,737)	13.60
Forfeited	(5,834)	16.50
Non-vested share awards outstanding at December 31, 2011	185,733	$ 15.25

The fair value of non-vested share awards equals the market value of the underlying stock on the date of grant. The weighted-average grant-date fair value of the non-vested share awards granted during the year ended December 31, 2011, the year ended December 31, 2010 and the period from October 1, 2009 through December 31, 2009 was $15.34, $11.70 and $7.67 per share, respectively. No non-vested share awards were granted during the period from January 1, 2009 through September 30, 2009. The total fair value of non-vested share awards that vested during the year ended December 31, 2011, the year ended December 31, 2010, the period from October 1, 2009 through December 31, 2009 and the period from January 1, 2009 through September 30, 2009 was $0.6 million, $0.5 million, $0.2 million and $0.1 million, respectively.

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The following table sets forth share-based compensation expense and related recognized tax benefits.

	Successor Company Year ended December 31, 2011	Successor Company Year ended December 31, 2010	Successor Company October 1, 2009 through December 31, 2009	Predecessor Company January 1, 2009 through September 30, 2009
		(in thousands)		
Compensation Expense (Benefit):				
Stock options	$ 1,497	$ 673	$ 14	$ 1,001
Non-vested share awards	1,012	500	229	2,688
Employee bonus share awards		82	174	
Deferred Income Tax Benefit	936	429	150	1,328

As of December 31, 2011, $3.6 million of total unrecognized compensation expense related to outstanding stock options was expected to be recognized over a weighted-average period of 2.1 years. As of December 31, 2011, $2.0 million of total unrecognized compensation expense related to non-vested share awards was expected to be recognized over a weighted-average period of approximately 2.3 years.

401(K) Plan

We also have a 401(K) Plan that covers all employees. We match 100% of each individual participant s contribution not to exceed 6% of the participant s compensation. Our matching contributions were made in the Company s common stock until 2009. During 2009, our 401(K) Plan was amended to require matching contributions to be made in cash. During the year ended December 31, 2011, the year ended December 31, 2010, the period from October 1, 2009 through December 31, 2009 and the period from January 1, 2009 through September 30, 2009, we made matching contributions in cash to the 401(K) Plan of approximately $0.7 million, $0.6 million, $0.2 million and $0.5 million, respectively.

Employee Retention Plans

In June 2009, we executed retention agreements with all of our non-officer, non-field employees, which called for payments of one-half of the retention amounts upon execution of the agreements and the remaining one-half upon exit from our Chapter 11 reorganization. Our field employees also received payments under this program. We also executed agreements with all of our officers (except for two executive officers who had individual change of control severance agreements with the Company) that called for payments of the entire retention amount upon exit from our Chapter 11 reorganization. During the period from January 1, 2009 through September 30, 2009, we recorded approximately $2.0 million for cash payments under these agreements. In addition, the remaining two executive officers terminated their written change of control severance agreements with the Company in exchange for receiving an unsecured claim for rejection damages in the Chapter 11 reorganization. In connection with these retention agreements, non-field employees and officers were required to waive and release the Company from any and all potential claims with respect to certain incentive and retention plans and agreements as provided for in the retention agreements. During the period from January 1 through September 30, 2009, we reduced previously established accruals totaling approximately $2.0 million for the various incentive and retention plans and agreements that were waived and released.

The Company has two plans under which, in the event of termination of employment in connection with a change of control of our company, our officers and employees are entitled to receive a multiple of their salaries and bonuses (typically up to one or two-and-one-half times such amount) and certain other benefits in a lump sum cash payment. Additionally, all options, restricted stock, restricted share units and other similar awards would become fully vested.

(13) Commitments and Contingencies

We have operating leases for office space and equipment, which expire on various dates through 2016. Future minimum commitments as of December 31, 2011 under these operating obligations are as follows (in thousands):

2012	$ 821
2013	894
2014	960
2015	961
2016	973
Thereafter	595
	$ 5,204

Expense relating to operating obligations for the year ended December 31, 2011, the year ended December 31, 2010, the period from October 1, 2009 through December 31, 2009 and the period from January 1, 2009 through September 30, 2009 was $1.8 million, $1.5 million, $0.7 million and $1.9 million, respectively.

We maintain restricted escrow funds in a trust for future abandonment costs at our East Bay property. The trust was originally funded with $15.0 million and, with accumulated interest, increased to $16.7 million at December 31, 2008. We may draw from the trust upon completion of qualifying abandonment activities at our East Bay field. At December 31, 2011, we had $6.0 million remaining in restricted escrow funds 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.

We record liabilities when we deliver production that is in excess of our interest in certain properties. In addition to these imbalances, we may, from time to time, be allocated cash sales proceeds in excess of amounts that we estimate are due to us for our interest in production. These allocations may be subject to further review, may require more information to resolve or may be in dispute. In July 2010, we were notified by a purchaser of oil production from one of our non-operated fields that we were allocated, and received sales proceeds from, more oil production than we actually sold to that purchaser. These third party misallocations may date back to 2006. The oil purchaser s initial estimate of the oil volumes misallocated to us was approximately 74,000 barrels, which may be valued at up to $6.9 million based on information provided by the oil purchaser. We have previously recorded an amount that we believe may be payable related to a potential reallocation, which amount is reflected in Accrued expenses in the accompanying condensed consolidated balance sheets as of December 31, 2011 and 2010.

We and our oil and gas joint interest owners are subject to periodic audits of the joint interest accounts for leases in which we participate and/or operate. As a result of these joint interest audits, amounts payable or receivable by us for costs incurred or revenue distributed by the operator or by us on a lease may be adjusted, resulting in adjustments, increases or decreases, to our net costs or revenues and the related cash flows. Such adjustments may be material. When they occur, these adjustments are recorded in the current period, which generally is one or more years after the related cost or revenue was incurred or recognized by the joint account.

As described in Notes 1 and 17, on May 1, 2009, we and certain of our subsidiaries filed for reorganization under Chapter 11.

In the ordinary course of business, we are a defendant in various other legal proceedings. We do not expect our exposure in these other proceedings, individually or in the aggregate, to have a material adverse effect on our financial position, results of operations or liquidity.

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(14) Interim Financial Information (Unaudited)

The following tables summarize our consolidated unaudited interim financial information for the years ended December 31, 2011 and 2010.

	Three Months Ended (In thousands, except per share data)			
	March 31	June 30	September 30	December 31
2011				
Revenues	$ 67,249	$ 92,830	$ 84,884	$ 103,364
Costs and expenses	60,175	61,571	69,232	90,223
Income from operations	7,074	31,259	15,652	13,141
Net income (loss) (1)	(14,509)	25,003	23,458	(7,341)
Earnings (loss) per share:				
Basic	$ (0.36)	$ 0.62	$ 0.59	$ (0.19)
Diluted	(0.36)	0.62	0.58	(0.19)

(1) Included in net income (loss) for the three months ended March 31 is the loss on extinguishment of debt of $2.4 million resulting from writing off the unamortized deferred financing costs associated with our terminated Amended Prior Credit Facility.

	Three Months Ended (In thousands, except per share data)			
	March 31	June 30	September 30	December 31
2010				
Revenues	$ 70,719	$ 58,197	$ 56,271	$ 54,722
Costs and expenses	56,608	62,874	63,457	49,661
Income (loss) from operations	14,111	(4,677)	(7,186)	5,061
Net income (loss) (1)	5,116	(4,610)	(7,846)	(1,128)
Earnings (loss) per share:				
Basic	$ 0.13	$ (0.12)	$ (0.20)	$ (0.03)
Diluted	0.13	(0.12)	(0.20)	(0.03)

(1) Included in net income (loss) for the three months ended June 30 is the loss on extinguishment of debt of $5.6 million resulting from the redemption of the PIK Notes.

(15) Supplementary Oil and Natural Gas Disclosures (Unaudited)

In December 2008, the SEC issued a final rule, Modernization of Oil and Gas Reporting, which amended its oil and gas reserves estimation and disclosure requirements. The new requirements were codified as part of ASC 932 in January 2010, and had the effect of, among other things: permitting the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes; modifying the prices used to estimate reserves for SEC disclosure purposes to an average price based upon the prior twelve month period rather than the year-end price; allowing the optional disclosure of probable and possible reserves to investors; allowing reserves to be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years (unless the specific circumstances justify a longer time); requiring disclosure regarding the qualifications of the chief technical person who oversees the reserves estimation process; requiring a general discussion of our internal controls used to ensure the objectivity of the reserves estimation process; and requiring that, if a third party is primarily responsible for preparing or auditing the reserve estimates, the company make disclosures relating to the independence and qualifications of the third party, including filing as an exhibit any report received from the third party. The revised rule was effective January 1, 2010 for reporting December 31, 2009 annual oil and natural gas reserve information. We adopted the provisions of the final rule in connection with the filing of our 2009 Annual Report.

Our estimates of proved reserves are based on reserve reports prepared as of December 31, 2011 by independent petroleum engineering firms Netherland, Sewell & Associates, Inc. and Ryder Scott Company, L.P. Users of this information should be aware that the process of estimating quantities of proved and proved developed natural gas and crude oil reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures. Proved reserves are estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

The following table sets forth our estimated net proved reserves, changes in our estimated net proved reserves and our proved developed reserves.

	Crude Oil (Mbbls)	Natural Gas (Mmcf)	Barrels of Oil Equivalent (Mboe)
Estimated Proved Reserves:			
December 31, 2008	21,637	90,808	36,771
Extensions, discoveries and other additions	70	2,203	437
Revisions	176	(4,765)	(617)
Production	(1,960)	(20,868)	(5,438)
December 31, 2009	19,923	67,378	31,153
Extensions, discoveries and other additions	652	489	733
Revisions (a)	(1,016)	8,892	466
Production	(2,336)	(15,508)	(4,921)
December 31, 2010	17,223	61,251	27,431
Acquisitions (b)	7,987	8,640	9,427
Extensions, discoveries and other additions	2,266	4,664	3,043
Revisions	2,778	(6,678)	1,666
Production	(2,953)	(9,092)	(4,468)
December 31, 2011	27,301	58,785	37,099
Proved developed reserves:			
December 31, 2009	15,026	57,139	24,549
December 31, 2010	15,974	56,410	25,376
December 31, 2011	24,791	52,739	33,581

(a) Crude oil revisions and natural gas revisions include decreases of approximately 3,093 Mbbls and 7,360 Mmcf, respectively, related to PUDs aged greater than five years for which funds were not committed in our 2011 development plan. Crude oil revisions also include a net increase of approximately 2,077 Mbbls primarily related to the crude oil price increase. Natural gas revisions also include positive revisions of 26,163 Mmcf related to the inclusion of estimated fuel gas in our natural gas reserves in the December 31, 2010 reserve volumes. This change in methodology reflects fuel gas as a production cost rather than negative natural gas reserves and does not impact future net cash flows after income taxes or standardized measure of discounted future net cash flows. The positive revisions related to the one-time change in the fuel gas methodology were partially offset by decreases of 7,813 Mmcf associated with underperformance of certain wells.

(b) Reserves acquired in the acquisitions of the ASOP Properties and Main Pass Interests.

Capitalized costs for oil and natural gas producing activities consist of the following:

	0000000000 2011	0000000000 2010
	(In thousands)	
Proved properties	$ 1,049,140	$ 687,759
Unproved properties	29,382	29,230
Accumulated depreciation, depletion and amortization	(303,566)	(167,417)
Net capitalized costs	$ 774,956	$ 549,572

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

	00000000	00000000	00000000
	Years Ended December 31,		
	2011	**2010**	**2009**
	(In thousands)		
Acquisitions Proved (1)	$ 261,812	$	$
Acquisitions Unproved	14	623	85
Exploration	17,129	31,463	2,477
Development (2)	83,577	25,643	8,815
Costs incurred	$ 362,532	$ 57,729	$ 11,377

(1) Includes asset retirement obligations associated with acquiring the ASOP Properties and Main Pass Interests totaling $26.4 million during the year ended December 31, 2011.

(2) Includes asset retirement obligations incurred associated with finding, acquiring and developing our proved oil and natural gas reserves of $0.2 million and $0.1 million during the years ended December 31, 2011 and 2010, respectively. No asset retirement obligations were incurred associated with finding, acquiring and developing our proved oil and natural gas reserves during the year ended December 31, 2009.

Expenditures incurred for exploratory dry holes are excluded from operating cash flows and included in investing activities in the consolidated statements of cash flows.

Standardized Measure of Discounted Future Net Cash Flows Relating to Reserves

The following information has been developed utilizing procedures prescribed by ASC 932. It may be useful for certain comparative purposes, but should not be solely relied upon in evaluating our performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of our oil and natural gas reserves or the current value of the Company.

We believe that the following factors should be taken into account in reviewing the following information: (1) future costs and sales prices are likely to differ materially from those required to be used in these calculations; (2) due to future market conditions, governmental regulations and other factors, actual rates of production achieved in future years may vary significantly from the rate of production assumed in the calculations; (3) the use of a 10% discount rate, while mandated under ASC 932, is arbitrary and may not be reasonable as a measure of the relative risk inherent in realizing future net oil and gas revenues; and (4) future net revenues may be subject to different rates of income taxation.

The Standardized Measure of Discounted Future Net Cash Flows uses future cash inflows estimated using oil and natural gas prices computed by applying the use of physical pricing based on the simple average of the closing price on the first day of each of the twelve months during the fiscal year (as required by ASC 932) and by 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. Future cash inflows were reduced by estimated future development, abandonment and production costs based on period-end costs with the assumption of the continuation of existing economic conditions in order to arrive at net cash flows before tax. Future income tax expense has been computed by applying period-end statutory tax rates to aggregate future net cash flows, reduced by the tax basis of the properties involved and tax carryforwards. Use of a 10% annual discount rate in computing Standardized Measure of Discounted Future Net Cash Flows is required by ASC 932.

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The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is as follows:

	2011	2010
	(In thousands)	
Future cash inflows	$ 3,133,430	$ 1,559,274
Future production costs(a)	(1,141,297)	(663,918)
Future development costs	(437,074)	(329,434)
Future income taxes	(322,454)	(73,446)
Future net cash flows after income taxes	1,232,605	492,476
10% annual discount for estimated timing of cash flows	(356,436)	(133,018)
Standardized measure of discounted future net cash flows	$ 876,169	$ 359,458

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved oil and natural gas reserves for the years ended December 31, 2011 and 2010 is as follows:

	2011	2010
	(In thousands)	
Beginning of the period	$ 359,458	$ 393,802
Sales and transfers of oil and natural gas produced, net of production costs	(266,120)	(179,168)
Net changes in prices and production costs (a)	461,719	120,892
Purchase of minerals in place	230,471	
Extensions, discoveries and improved recoveries, net of future production costs	139,757	16,014
Revision of quantity estimates	54,329	11,305
Previously estimated development costs incurred during the period	27,066	20,759
Changes in estimated future development costs	24,662	(7,221)
Changes in production rates (timing) and other	(25,655)	(5,112)
Accretion of discount	41,307	39,600
Net change in income taxes (b)	(170,825)	(51,413)
Net increase (decrease)	516,711	(34,344)
End of period	$ 876,169	$ 359,458

(a) Our 2010 estimated future production costs reflect an increase related to the previously described one-time change in the fuel gas methodology to reflect fuel gas as a production cost rather than negative natural gas reserves in addition to an increase related to estimated reserve life due primarily to the crude oil price increase.

(b) Our estimated future income taxes were impacted by our reorganization which resulted in a reduction in our NOLs (See Note 11, Income Taxes).

At December 31, 2011 and 2010, the computation of the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves was based on the following computed prices:

	2011	2010
per barrel for oil	$ 108.48	$ 77.85
per Mcf for natural gas	$ 4.16	$ 4.54

(16) Supplemental Condensed Consolidating Financial Information

In connection with the 8.25% Notes offering described in Note 7, all of our existing direct and indirect domestic subsidiaries (other than immaterial subsidiaries) (the Guarantor Subsidiaries) jointly, severally and unconditionally guaranteed the payment obligations under the 8.25% Notes. The following supplemental financial information sets forth, on a consolidating basis, the balance sheet, statement of operations and cash flow information for Energy Partners, Ltd. (Parent Company Only) and for the Guarantor Subsidiaries. We have not presented separate financial statements and other disclosures concerning the Guarantor Subsidiaries because management has determined that such information is not material to investors.

The supplemental condensed consolidating financial information has been prepared pursuant to the rules and regulations for condensed financial information and does not include all disclosures included in annual financial statements.

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Certain reclassifications were made to conform all of the financial information to the financial presentation on a consolidated basis. The principal eliminating entries eliminate investments in subsidiaries, intercompany balances and intercompany revenues and expenses.

Supplemental Condensed Consolidating Balance Sheet

As of December 31, 2011

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
ASSETS				
Current assets:				
Cash and cash equivalents	$ 80,128	$	$	$ 80,128
Accounts receivable	93,882	131	(62,196)	31,817
Other current assets	11,633			11,633
Total current assets	185,643	131	(62,196)	123,578
Property and equipment	833,932	248,316		1,082,248
Less accumulated depreciation, depletion and amortization	(251,948)	(53,162)		(305,110)
Net property and equipment	581,984	195,154		777,138
Investment in affiliates	91,768		(91,768)	
Notes receivable, long-term		69,000	(69,000)	
Other assets	14,504			14,504
	873,899	264,285	(222,964)	915,220
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities:				
Accounts payable and accrued expenses	$ 99,096	$ 72,609	$ (62,196)	$ 109,509
Deferred tax liabilities	2,823			2,823
Fair value of commodity derivative instruments	1,056			1,056
Total current liabilities	102,975	72,609	(62,196)	113,388
Long-term debt	204,390	69,000	(69,000)	204,390
Other liabilities	75,489	30,908		106,397
	382,854	172,517	(131,196)	424,175
Stockholders equity:				
Preferred stock		3	(3)	
Common stock	40	98	(98)	40
Additional paid-in capital	505,235	84,900	(84,900)	505,235
Treasury stock	(11,361)			(11,361)
Retained earnings (accumulated deficit)	(2,869)	6,767	(6,767)	(2,869)
Total stockholders equity	491,045	91,768	(91,768)	491,045
	873,899	264,285	(222,964)	915,220

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Supplemental Condensed Consolidating Balance Sheet

As of December 31, 2010

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
ASSETS				
Current assets:				
Cash and cash equivalents	$ 33,553	$	$	$ 33,553
Accounts receivable	73,040	259	(49,768)	23,531
Other current assets	4,508	1,674		6,182
Total current assets	111,101	1,933	(49,768)	63,266
Property and equipment	512,569	206,578		719,147
Less accumulated depreciation, depletion and amortization	(137,284)	(30,771)		(168,055)
Net property and equipment	375,285	175,807		551,092
Investment in affiliates	76,236		(76,236)	
Notes receivable, long-term		69,000	(69,000)	
Other assets	12,548			12,548
	575,170	246,740	(195,004)	626,906
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities:				
Accounts payable and accrued expenses	$ 50,756	$ 62,666	$ (49,768)	$ 63,654
Fair value of commodity derivative instruments	12,320			12,320
Total current liabilities	63,076	62,666	(49,768)	75,974
Long-term debt		69,000	(69,000)	
Other liabilities	38,978	38,838		77,816
	102,054	170,504	(118,768)	153,790
Stockholders equity:				
Preferred stock		3	(3)	
Common stock	40	98	(98)	40
Additional paid-in capital	502,556	84,900	(84,900)	502,556
Retained earnings (accumulated deficit)	(29,480)	(8,765)	8,765	(29,480)
Total stockholders equity	473,116	76,236	(76,236)	473,116
	575,170	246,740	(195,004)	626,906

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Supplemental Condensed Consolidating Statement of Operations

Year Ended December 31, 2011

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Revenue:				
Oil and natural gas	$ 245,567	$ 102,640	$	$ 348,207
Other	15,007	113	(15,000)	120
	260,574	102,753	(15,000)	348,327
Costs and expenses:				
Lease operating expenses	51,618	18,663		70,281
Taxes, other than on earnings	(733)	15,098		14,365
Exploration expenditures, dry hole cost and impairments	46,577	157		46,734
Depreciation, depletion, amortization and accretion	91,180	29,386		120,566
General and administrative	18,282	15,459	(15,000)	18,741
Other expenses	10,706	(192)		10,514
Total costs and expenses	217,630	78,571	(15,000)	281,201
Income from operations	42,944	24,182		67,126
Other income (expense):				
Interest expense, net	(17,446)			(17,446)
Loss on derivative instruments	(5,870)			(5,870)
Loss on extinguishment of debt	(2,377)			(2,377)
Income from equity investments	15,532		(15,532)	
Income before income taxes	32,783	24,182	(15,532)	41,433
Income taxes	(6,172)	(8,650)		(14,822)
Net income	$ 26,611	$ 15,532	$ (15,532)	$ 26,611

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Supplemental Condensed Consolidating Statement of Operations

Year Ended December 31, 2010

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Revenue:				
Oil and natural gas	$ 171,176	$ 68,594	$	$ 239,770
Other	15,008	131	(15,000)	139
	186,184	68,725	(15,000)	239,909
Costs and expenses:				
Lease operating expenses	34,004	18,361		52,365
Taxes, other than on earnings	681	9,452		10,133
Exploration expenditures, dry hole cost and impairments	28,715	3,868		32,583
Depreciation, depletion, amortization and accretion	89,690	27,716		117,406
General and administrative	17,737	15,341	(15,000)	18,078
Other expenses	2,203	(168)		2,035
Total costs and expenses	173,030	74,570	(15,000)	232,600
Income (loss) from operations	13,154	(5,845)		7,309
Other income (expense):				
Interest expense, net	(9,694)			(9,694)
Gain (loss) on derivative instruments	(4,865)			(4,865)
Loss on extinguishment of debt	(5,627)			(5,627)
Loss from equity investments	(3,846)		3,846	
Loss before income taxes	(10,878)	(5,845)	3,846	(12,877)
Income taxes	2,410	1,999		4,409
Net loss	$ (8,468)	$ (3,846)	$ 3,846	$ (8,468)

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Supplemental Condensed Consolidating Statement of Operations

Period From October 1, 2009 through December 31, 2009

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Revenue:				
Oil and natural gas	$ 42,054	$ 14,654	$	$ 56,708
Other	3,754	38	(3,750)	42
	45,808	14,692	(3,750)	56,750
Costs and expenses:				
Lease operating expenses	7,803	5,607		13,410
Taxes, other than on earnings	197	1,886		2,083
Exploration expenditures, dry hole cost and impairments	3,574	5,393		8,967
Depreciation, depletion, amortization and accretion	25,947	5,525		31,472
General and administrative	4,415	3,872	(3,750)	4,537
Other expenses	804			804
Total costs and expenses	42,740	22,283	(3,750)	61,273
Income (loss) from operations	3,068	(7,591)		(4,523)
Other income (expense):				
Interest expense, net	(4,319)			(4,319)
Gain (loss) on derivative instruments	(22,705)			(22,705)
Loss from equity investments	(4,919)		4,919	
Income (loss) before income taxes and reorganization items	(28,875)	(7,591)	4,919	(31,547)
Reorganization items	(865)			(865)
Income (loss) before income taxes	(29,740)	(7,591)	4,919	(32,412)
Income taxes	8,728	2,672		11,400
Net income (loss)	$ (21,012)	$ (4,919)	$ 4,919	$ (21,012)

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Supplemental Condensed Consolidating Statement of Operations

Period From January 1, 2009 through September 30, 2009

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Revenue:				
Oil and natural gas	$ 98,897	$ 35,686	$	$ 134,583
Other	11,432	120	(11,250)	302
	110,329	35,806	(11,250)	134,885
Costs and expenses:				
Lease operating expenses	31,335	14,961		46,296
Taxes, other than on earnings	41	5,946		5,987
Exploration expenditures, dry hole cost and impairments	9,685	47		9,732
Depreciation, depletion, amortization and accretion	87,984	13,496		101,480
General and administrative	18,684	12,059	(11,250)	19,493
Other expenses	4,403	2		4,405
Total costs and expenses	152,132	46,511	(11,250)	187,393
Business interruption recovery	1,185			(1,185)
Income (loss) from operations	(40,618)	(10,705)		(51,323)
Other income (expense):				
Interest expense, net	(17,766)			(17,766)
Gain (loss) on derivative instruments	2,728			2,728
Income from equity investments	315		(315)	
Income (loss) before income taxes and reorganization items	(55,341)	(10,705)	(315)	(66,361)
Reorganization items	(24,198)			(24,198)
Loss on discharge of debt	(2,666)			(2,666)
Fresh-start adjustments	46,091	11,020		57,111
Income (loss) before income taxes	(36,114)	315	(315)	(36,114)
Income taxes				
Net income (loss)	$ (36,114)	$ 315	$ (315)	$ (36,114)

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Supplemental Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2011

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Net cash provided by operating activities	$ 136,245	$ 35,007	$	$ 171,252
Cash flows provided by (used in) investing activities:				
Property acquisitions	(235,486)			(235,486)
Exploration and development expenditures	(40,996)	(35,007)		(76,003)
Other property and equipment additions	(1,568)			(1,568)
Decrease in restricted cash	2,466			2,466
Net cash used in investing activities	(275,584)	(35,007)		(310,591)
Cash flows provided by (used in) financing activities:				
Proceeds from long-term debt	203,794			203,794
Deferred financing costs	(6,646)			(6,646)
Purchase of shares into treasury	(11,353)			(11,353)
Exercise of stock options	119			119
Net cash used in financing activities	185,914			185,914
Net increase in cash and cash equivalents	46,575			46,575
Cash and cash equivalents at the beginning of the period	33,553			33,553
Cash and cash equivalents at the end of the period	$ 80,128	$	$	$ 80,128

Supplemental Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2010

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Net cash provided by operating activities	$ 84,613	$ 42,767	$	$ 127,380
Cash flows provided by (used in) investing activities:				
Property acquisitions	(623)			(623)
Exploration and development expenditures	(15,416)	(42,767)		(58,183)
Other property and equipment additions	(755)			(755)
Decrease in restricted cash	13,658			13,658
Net cash used in investing activities	(3,136)	(42,767)		(45,903)
Cash flows provided by (used in) financing activities:				
Deferred financing costs	(181)			(181)
Repayments of long-term debt	(94,882)			(94,882)
Proceeds from long-term debt	20,394			20,394
Net cash used in financing activities	(74,669)			(74,669)

Net increase in cash and cash equivalents	6,808			6,808
Cash and cash equivalents at the beginning of the period	26,745			26,745
Cash and cash equivalents at the end of the period	$ 33,553	$	$	$ 33,553

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Supplemental Condensed Consolidating Statement of Cash Flows

Period From October 1, 2009 through December 31, 2009

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Net cash provided by operating activities	$ 14,074	$ 2,794	$	$ 16,868
Cash flows used in investing activities:				
Property acquisitions	(54)			(54)
Exploration and development expenditures	63	(2,794)		(2,731)
Other property and equipment additions	(23)			(23)
Net cash used in investing activities	(14)	(2,794)		(2,808)
Cash flows provided by (used in) financing activities:				
Repayments of long-term debt	(31,250)			(31,250)
Net cash used in financing activities	(31,250)			(31,250)
Net decrease in cash and cash equivalents	(17,190)			(17,190)
Cash and cash equivalents at the beginning of the period	43,935			43,935
Cash and cash equivalents at the end of the period	$ 26,745	$	$	$ 26,745

Supplemental Condensed Consolidating Statement of Cash Flows

Period From January 1, 2009 through September 30, 2009

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Net cash provided by operating activities	$ 12,178	$ 2,188	$	$ 14,366
Cash flows used in investing activities:				
Property acquisitions	(31)			(31)
Exploration and development expenditures	(27,535)	(2,188)		(29,723)
Other property and equipment additions	(147)			(147)
Proceeds from the sale of oil and natural gas assets	150			150
Net cash used in investing activities	(27,563)	(2,188)		(29,751)
Cash flows provided by (used in) financing activities:				
Deferred financing costs	(798)			(798)
Repayments of long-term debt	(55,001)			(55,001)
Proceeds from long-term debt	113,128			113,128
Net cash provided by financing activities	57,329			57,329
Net decrease in cash and cash equivalents	41,944			41,944
Cash and cash equivalents at the beginning of the period	1,991			1,991

Cash and cash equivalents at the end of the period	$ 43,935	$	$	$ 43,935

(17) Reorganization and Fresh-Start Accounting

The financial statements for the period in which the Company was in reorganization under Chapter 11 were prepared in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 852 (ASC 852), Reorganizations, (originally issued as the American Institute of Certified Public Accountant s Statement of Position 90-7, Financial Reporting by Entities in Reorganization Under the Bankruptcy Code). Under ASC 852, we were required to, among other things, (1) identify transactions that were directly associated with the reorganization from those events that occurred during the normal course of business, (2) identify pre-petition liabilities subject to compromise from those that were not subject to compromise or were post-petition liabilities and (3) apply fresh-start accounting rules upon emergence from Chapter 11 reorganization. In accordance with the Plan of Reorganization, only the Predecessor Company Notes and the related accrued interest were discharged in the reorganization. As a result, we discontinued accruing interest on the Predecessor Company Notes as of the Petition Date.

On the Exit Date, we consummated certain transactions contemplated by the Plan of Reorganization, including entering into a senior secured credit facility consisting of a $125 million revolving credit facility with an initial borrowing base of $45 million (the Prior Revolver) and a $25 million one-year amortizing term loan facility (together with the Revolver, the Prior Credit Facility). We also issued 20% Senior Subordinated Secured PIK Notes due 2014 in an aggregate principal amount of $61.1 million. The PIK Notes were issued with original issue discount, and the note proceeds after this discount were $55.0 million. As of September 28, 2009, we had satisfied the hedging requirements under the Prior Credit Facility and had delivered to the Minerals Management Service the financial support related to abandonment obligations on certain federal leases in the Gulf of Mexico.

We reflected the reorganization and application of ASC 852 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 Successor Company to its assets and liabilities in relation to their fair values. Based on financial projections that we and our advisors developed, the allocation of the reorganization value was determined using various valuation methods, including (i) comparable company analysis, which estimates the value of the Company based on the implied valuations of other similar companies; (ii) comparable asset transaction analysis, which estimates the value of a company based upon publicly announced transactions of assets with similar characteristics; (iii) comparable merger transaction analysis, which, much like comparable asset transaction analysis, estimates the value of a company based upon publicly announced transactions with similar characteristics, except that merger analysis analyzes public to public merger transactions rather than solely asset transactions; and (iv) discounted cash flow analysis, which estimates the value of the Company by determining the present value of estimated future cash flows. The reorganization value is based on subjective estimates and assumptions, which are inherently subject to significant uncertainties and contingencies which are beyond our control. The fair value allocated to our property and equipment should not be viewed as representative of the current value of our oil and natural gas reserves or the current value of the Company. The reorganization value of the Company was estimated to be approximately $603 million.

In order to reflect the reorganization and application of ASC 852, we adjusted the book values of the Predecessor Company s assets and liabilities to reflect the estimated fair values of the Successor Company s assets and liabilities, on a net basis. These adjustments increased net income by $57.1 million in the period from January 1, 2009 through September 30, 2009. The restructuring of the Company s capital (see Note 3) and resulting discharge of the Predecessor Company Notes and related accrued interest resulted in a loss of $2.7 million in the period from January 1, 2009 through September 30, 2009. The adjustments for the revaluation of the assets and liabilities and the loss on the discharge of pre-petition debt are recorded in Fresh-start adjustments and Loss on discharge of debt, respectively, in the condensed consolidated statement of operations.

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The following table reflects the reorganization and application of ASC 852 on our condensed consolidated balance sheet as of September 30, 2009:

(In thousands)	Predecessor Company as of September 30, 2009	Reorganization Adjustments (1)	Fresh-Start Adjustments (2)	Successor Company as of September 30, 2009
ASSETS				
Current assets:				
Cash and cash equivalents	$ 43,935	$	$	$ 43,935
Trade accounts receivable	24,457			24,457
Receivables from insurance	4,036			4,036
Fair value of commodity derivative instruments		2,379		2,379
Prepaid expenses	4,445			4,445
Total current assets	76,873	2,379		79,252
Property and equipment	1,645,651		(1,026,377)	619,274
Less accumulated depreciation, depletion and amortization	(1,057,701)		1,057,701	
Net property and equipment	587,950		31,324	619,274
Restricted cash	22,148			22,148
Other assets	1,712	2,863		4,575
Deferred financing costs		2,988		2,988
	$ 688,683	$ 8,230	$ 31,324	$ 728,237
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities:				
Accounts payable	$ 23,487	$ (6,320)	$	$ 17,167
Accrued expenses	43,739	(6,366)		37,373
Accrued interest on indebtedness	1,516	(1,085)		431
Asset retirement obligations	9,308			9,308
Secured bank credit facility	83,000	(83,000)		
Secured bank credit facility term loan		25,000		25,000
Total current liabilities	161,050	(71,771)		89,279
Liabilities subject to compromise:				
Senior unsecured debt	454,501	(454,501)		
Accrued interest on senior unsecured debt	18,663	(18,663)		
Long-term debt		80,001		80,001
Asset retirement obligations	83,679		(25,787)	57,892
Other liabilities	191			191
	718,084	(464,934)	(25,787)	227,363
Stockholders equity:				
Preferred stock				
Common stock	447	(407)		40
Additional paid-in capital	386,268	114,566		500,834
Accumulated deficit	(157,760)	100,649	57,111	
Treasury stock	(258,356)	258,356		
Total stockholders equity	(29,401)	473,164	57,111	500,874

	$ 688,683	$ 8,230	$ 31,324	$ 728,237

(1) To record the discharge of liabilities subject to compromise, the conversion of the Predecessor Company s common stock into new common stock of the Successor Company and to reduce the Predecessor Company s accumulated deficit to zero. This column also reflects the following:

payment of pre-petition vendor claims totaling $6.3 million;

premiums of $5.2 million associated with hedging requirements under the Prior Credit Facility;

payment of Predecessor Company secured bank credit facility and related accrued interest;

payments totaling approximately $9.4 million for financing costs and certain reorganization items; and

loss on discharge of debt of $2.7 million reflected in accumulated deficit.

(2) To adjust assets and liabilities to fair values.

The fair value assigned to our proved oil and natural gas properties as of September 30, 2009 was estimated by adjusting the pre-tax future cash flows from our proved reserves as set forth in our reserve reports prepared by our independent reservoir engineers as of December 31, 2008 to reflect the production for the period from December 31, 2008 through September 30, 2009 and to reflect other revisions of reserve quantities identified during 2009, which revisions were not significant. We used the NYMEX forward price curve of oil and natural gas as of September 30, 2009 to estimate the future selling price of our reserves, which we escalated at a 2.5% inflation rate for periods beyond the limits of the NYMEX forward price curve. The weighted average prices of oil and natural gas reflected in our estimate of the fair value of proved reserves were $83.88 per barrel of oil and $6.98 per mcf of natural gas. Proved reserve volumes were risk-adjusted by reference to the Society of Petroleum Engineers 28th Annual Survey of Economic Parameters (June 2009) (SPEE Survey) based on the reserve category as follows: (i) proved developed producing 100%; (ii) proved non-producing 80%; (iii) proved behind pipe 80%; (iv) proved undeveloped 65%. Probable and possible reserves were risk-adjusted at 35% and 10%, respectively, by reference to the SPEE Survey. Estimated income taxes were deducted from future cash flows at a rate of 8.6%, which reflects the estimated rate of payment of cash taxes with reference to comparable companies. Net estimated future cash flows after estimated operating costs were discounted at 14.4% per year by reference to the SPEE Survey.

Our asset retirement obligations changed as a result of the application of ASC 852 because the discount rate and inflation rate applied to the estimated future abandonment costs in order to determine the fair value as of September 30, 2009 differed from the discount rates and inflation rates used to establish asset retirement obligations in prior periods under ASC Topic 410, Asset Retirement and Environmental Obligations.

Under ASC 852, certain costs and income items resulting from the reorganization and restructuring of the business were reported separately as reorganization items classified as non-operating expenses. Our reorganization items were as follows:

(In thousands)	Successor Company Period from October 1, 2009 through December 31, 2009	Predecessor Company Period from January 1, 2009 through September 30, 2009
Amortization of deferred financing costs	$	$ 6,838
Professional fees	785	14,462
Directors and officers insurance premium		1,573
Provision for rejected/renegotiated contracts	80	1,300
Employee agreements		25
Total reorganization items	$ 865	$ 24,198

Deferred financing costs as of the Petition Date associated with the Predecessor Company Notes were written off in accordance with the provisions of ASC 852. We also wrote off the remaining balance of deferred financing costs associated with the Predecessor Company s bank credit facility which was repaid in connection with our emergence from Chapter 11 reorganization.

We retained advisors to assist in our reorganization under Chapter 11 and incurred significant costs associated with the restructuring. Professional fees primarily relate to fees paid to our financial and legal advisors, the advisors to our creditors that we were obligated to pay under certain agreements and the advisors to the official committees appointed during our Chapter 11 proceedings. During the period from

January 1 to September 30, 2009, we made cash payments for these professional fees, including retainers, totaling approximately $9.0 million which were included in our cash flows from operating activities for the period. In addition to monthly fees, as of September 30, 2009, we had accrued a success fee of $3.4 million that we were obligated to pay to our financial advisor under our agreement with that firm, which is included in professional fees in the table above. This fee was paid during the period from October 1, 2009 through December 31, 2009.

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Prior to our filing for reorganization under Chapter 11, we purchased a six-year extension to our directors and officers insurance coverage (commonly referred to as a tail policy). The premium amount of $1.6 million was recorded and paid in cash during the period from January 1 to September 30, 2009.

During September, 2009, with the approval of the Bankruptcy Court, we renegotiated the lease for our corporate office in Louisiana and rejected the lease for our office in Texas and recorded $1.4 million in associated costs, $0.9 million of which was paid during the period from October 1, 2009 through December 31, 2009. Approximately $0.5 million was paid in 2010, representing the final payment due on our lease renegotiations.

In June 2009, we executed retention agreements with all of our non-officer, non-field employees, which called for payments of one-half of the retention amounts upon execution of the agreements and the remaining one-half upon exit from our Chapter 11 reorganization. Our field employees also received payments under this program. We also executed agreements with all of our officers (except for two executive officers who had individual change of control severance agreements with the Company) that called for payments of the entire retention amount upon exit from our Chapter 11 reorganization. During the period from January 1, 2009 through September 30, 2009, we recorded approximately $2.0 million for cash payments under these agreements. In addition, the remaining two executive officers terminated their written change of control severance agreements with the Company in exchange for receiving an unsecured claim for rejection damages in the Chapter 11 reorganization. In connection with these retention agreements, non-field employees and officers were required to waive and release the Company from any and all potential claims with respect to certain incentive and retention plans and agreements as provided for in the retention agreements. During the period from January 1, 2009 through September 30, 2009, we reduced previously established accruals totaling approximately $2.0 million for the various incentive and retention plans and agreements that were waived and released.

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

As previously reported in our Current Report on Form 8-K filed on July 1, 2010, on June 28, 2010, the Company dismissed KPMG LLP (KPMG) as its independent registered public accounting firm and engaged PricewaterhouseCoopers LLP as the Company s independent registered public accounting firm. The Company s Audit Committee recommended and approved the decision to change the Company s independent registered public accounting firm.

None of KPMG s reports on the Company s consolidated financial statements for the Company s fiscal years ended December 31, 2009 and December 31, 2008 contained any adverse opinion or disclaimer of opinion, or were qualified or modified as to uncertainty, audit scope or accounting principles, except for KPMG s report on the Company s consolidated financial statements as of December 31, 2008, and for the year then ended, which was modified as to uncertainty because of substantial doubt about the Company s ability to continue as a going concern.

During the fiscal years ended December 31, 2009 and December 31, 2008 and through the date hereof, there were no disagreements between the Company and KPMG on any matter of accounting principles or practices, financial statement disclosure or auditing scope or procedure, which disagreements, if not resolved to KPMG s satisfaction, would have caused KPMG to make a reference to the matter in its reports on the Company s financial statements for such years.

During the fiscal years ended December 31, 2009 and December 31, 2008 and through the date hereof, there were no reportable events (as defined by Item 304(a)(1)(v) of Regulation S-K), except that, as disclosed in the Company s Annual Report on Form 10-K for the year ended December 31, 2008, the Company identified the following material weaknesses in the Company s internal control over financial reporting as of December 31, 2008:

Control Environment over Financial Reporting. The Company lacked sufficient resources and accounting expertise to perform effective supervisory reviews and monitoring activities over financial reporting matters and controls related to matters involving judgments and estimates.

Complex or Non-Routine Accounting Matters. The Company lacked sufficient expertise and resources within the organization to effectively identify and evaluate the financial reporting implications of complex or non-routine accounting matters, such as application of SFAS No. 143, Accounting for Asset Retirement Obligations.

Period-End Financial Reporting Process. The Company also lacked sufficient expertise and resources within the organization to ensure journal entries, both recurring and non-recurring, were accompanied by sufficient supporting documentation and were adequately reviewed and approved prior to being recorded.

As a result of the above material weaknesses, there were material errors in the Company s asset retirement obligations and impairments, and those errors were corrected prior to the issuance of the Company s financial statements. The Company reported no material weaknesses in its internal control over financial reporting as of December 31, 2009 in its Annual Report on Form 10-K for the year ended December 31, 2009.

KPMG furnished the Company with a letter addressed to the SEC stating that it agrees with the above statements, which letter we filed as Exhibit 16.1 to our Current Report on Form 8-K filed on July 1, 2010.

As described above, on June 28, 2010, the Company engaged PricewaterhouseCoopers LLP to serve as its independent registered public accounting firm for the fiscal year ended December 31, 2010 and to perform procedures related to the financial statements included in our Quarterly Reports of Form 10-Q, which commenced with and included the quarter ended June 30, 2010.

During the Company s fiscal years ended December 31, 2009 and 2008 and during any subsequent interim period prior to the date of engagement of PricewaterhouseCoopers as our independent registered public accounting firm, the Company has not consulted PricewaterhouseCoopers LLP regarding any of the matters set forth in Item 304(a)(2)(i) or (ii) of Regulation S-K.

Item 9A. Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) are designed to ensure that information required to be disclosed in our reports filed under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. This information is also accumulated and communicated to management, including our principal executive officer and our principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Our management, under the supervision and with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the most recent fiscal quarter reported on herein. Based on that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2011.

Because of their inherent limitations, disclosure controls and procedures may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that such controls and procedures may become inadequate because of changes in conditions, or that the degree of compliance with the controls or procedures may deteriorate. Accordingly, even effective disclosure controls and procedures can provide only reasonable assurance of achieving their control objectives.

(b) Management s Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with GAAP. In connection with our annual evaluation of internal control over financial reporting, our management, under the supervision and with the participation of our principal executive officer and principal financial officer, assessed the effectiveness as of December 31, 2011, of our internal control over financial reporting based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, our management, including our principal executive officer and principal financial officer, concluded that our internal controls over financial reporting were effective as of December 31, 2011.

Because of their inherent limitations, internal controls 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.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting as of December 31, 2011. See Report of Independent Registered Public Accounting Firm in Part II, Item 8 of this Annual Report.

(c) Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the three months ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

None.

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PART III

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

Except as set forth below, for information required by Item 10 regarding our directors and executive officers, see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on or about May 1, 2012, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

Code of Ethics

We have adopted a Corporate Code of Business Conduct and Ethics that applies to all directors and employees, including our chief executive officer, chief financial officer and controller. A copy of the code is available on our website at www.eplweb.com. A copy of the code is also available, at no cost, by writing to our Corporate Secretary at 201 St. Charles Avenue, Suite 3400, New Orleans, Louisiana, 70170. We will post on our website any waiver of the code granted to any of our directors or executive officers promptly following the date of the amendment or waiver. No such waiver has ever been sought or granted.

Item 11. ***Executive Compensation***

For information required by Item 11, see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on or about May 1, 2012, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

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

Except as set forth below, for information required by Item 12, see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on or about May 1, 2012, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

Securities Authorized for Issuance under Equity Compensation Plans

The information contained in Part II, Item 5, Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities, of this Annual Report is incorporated by reference.

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

For information required by Item 13, see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on or about May 1, 2012, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

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

For information required by Item 14, see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on or about May 1, 2012, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

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PART IV

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

(a) Documents to be filed as part of this Annual Report

1. Financial Statements

The following items are included in Part II, Item 8 this Annual Report:

Independent Registered Public Accounting Firms Reports

Consolidated Balance Sheets as of December 31, 2011 and 2010

Consolidated Statements of Operations for the years ended December 31, 2011 and 2010, the period from October 1, 2009 through December 31, 2009 and the period from January 1, 2009 through September 30, 2009

Consolidated Statements of Changes in Stockholders Equity for the years ended December 31, 2011 and 2010, the period from October 1, 2009 through December 31, 2009 and the period from January 1, 2009 through September 30, 2009

Consolidated Statements of Cash Flows for the years ended December 31, 2011 and 2010, the period from October 1, 2009 through December 31, 2009 and the period from January 1, 2009 through September 30, 2009

Notes to the Consolidated Financial Statements

2. Financial Statement Schedules

All schedules have been omitted because the information is not required or not in amounts sufficient to require submission of the schedule, or because the information required is included in the consolidated financial statements and notes thereto.

3. Exhibits

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EXHIBITS

The exhibits marked with the cross symbol ( ) are management contracts or compensatory plans or arrangements filed pursuant to Item 601(b)(10)(iii) of Regulation S-K.

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed/ Furnished Herewith
2.0	Second Amended Joint Plan of Reorganization of Energy Partners, Ltd. and certain of its Subsidiaries Under Chapter 11 of the Bankruptcy Code, as Modified as of September 16, 2009	10-Q	001-16179	2.0	05/06/2010	
2.1	Purchase and Sale Agreement dated January 13, 2011, by and between Anglo-Suisse Offshore Partners, LLC and Energy Partners, Ltd.	8-K	001-16179	2.1	01/18/2011	
2.2	Purchase and Sale Agreement dated October 28, 2011, by and between Stone Energy Offshore, LLC and Energy Partners, Ltd.	8-K	001-16179	2.1	11/02/2011	
3.1	Amended and Restated Certificate of Incorporation of Energy Partners, Ltd. dated as of September 21, 2009	8-A/A	001-16179	3.1	09/21/2009	
3.2	Second Amended and Restated Bylaws of Energy Partners, Ltd.	8-A/A	001-16179	3.2	09/21/2009	
4.1	Indenture by and among Energy Partners, Ltd., as Issuer, the Guarantors named therein and U.S. Bank National Association, as Trustee dated February 14, 2011	8-K	001-16179	4.1	02/15/2011	
4.2	Supplemental Indenture by and among Anglo-Suisse Offshore Pipeline Partners, LLC, as a Guarantor, Energy Partners, Ltd., as Issuer, the other Guarantors named therein and U.S. Bank National Association, as Trustee dated March 14, 2011	S-4	333-175567	4.2	07/14/2011	
10.1	Registration Rights Agreement by and among Energy Partners, Ltd., the Guarantors named therein and the initial purchasers named therein dated February 14, 2011	8-K	001-16179	10.1	02/15/2011	
10.2	Credit Agreement by and among Energy Partners, Ltd., as Borrower, Bank of Montreal, as Administrative Agent, and certain financial institutions, as Lenders, dated February 14, 2011	8-K	001-16179	10.2	02/15/2011	
10.3	Exchange Agreement between Energy Partners, Ltd. and Mellon Investor Services LLC (operating with the service name BNY Mellon Shareowner Services), as Agent dated September 15, 2009	8-K	001-16179	10.4	09/25/2009	
10.4	Change of Control Severance Plan effective as of March 24, 2005	8-K	001-16179	10.2	03/30/2005	
10.5	First Amendment to Change of Control Severance Plan effective as of September 13, 2006	8-K	001-16179	10.3	09/14/2006	

10.6	Second Amendment to Change of Control Severance Plan effective as of April 16, 2008	8-K	001-16179	10.3	05/08/2008
10.7	Third Amendment to Change of Control Severance Plan dated November 13, 2008	8-K	001-16179	10.2	11/14/2008
10.8	Fourth Amendment to Change of Control Severance Plan dated November 13, 2008	10-K	001-16179	10.8	03/11/2010

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed/ Furnished Herewith
10.9	Fifth Amendment to Change of Control Severance Plan	10-Q	001-16179	10.2	08/05/2010	
10.10	Term sheet with the United States Department of the Interior, Minerals Management Service dated April 30, 2009	10-K	001-16179	10.6	08/05/2009	
10.11	Employment Agreement dated as of October 1, 2009 between Energy Partners, Ltd. and Gary Hanna	8-K	001-16179	10.1	10/06/2009	
10.12	First Amendment to Employment Agreement dated as of April 12, 2010 between Energy Partners, Ltd. and Gary Hanna	10-Q	001-16179	10.3	08/05/2010	
10.13	Option Award Agreement dated as of September 30, 2009 between Energy Partners, Ltd. and Gary Hanna	8-K	001-16179	10.2	10/06/2009	
10.14	Settlement Agreement dated as of June 23, 2009 by and between Energy Partners, Ltd. and John H. Peper	10-K	001-16179	10.51	08/05/2009	
10.15	Energy Partners, Ltd. 2009 Long Term Incentive Plan	S-8	333-162185	4.5	09/29/2009	
10.16	Form of 2009 Long Term Incentive Plan Option Award Agreement	8-K	001-16179	10.5	09/25/2009	
10.17	Form of 2009 Long Term Incentive Plan Restricted Stock Agreement	8-K	001-16179	10.6	09/25/2009	
10.18	Form of Indemnification Agreement for Directors	8-K	001-16179	10.1	11/24/2009	
10.19	Form of Indemnification Agreement for Officers	8-K	001-16179	10.2	11/24/2009	
10.20	Energy Partners, Ltd. Board Compensation Program	8-K	001-16179	10.1	11/12/2009	
10.21	Second Amended and Restated Stock and Deferral Plan for Non-Employee Directors, dated as of November 6, 2009	8-K	001-16179	10.2	11/12/2009	
10.22	Form of Director Deferred Share Agreement	8-K	001-16179	10.3	11/12/2009	
10.23	First Amendment to the Energy Partners, Ltd. 2009 Long Term Incentive Plan					X
10.24	Employment Agreement dated as of February 1, 2012 between Energy Partners, Ltd. and John H. Peper					X
16.1	Letter from KPMG LLP dated July 1, 2010, addressed to the Securities and Exchange Commission	8-K	001-16179	16.1	07/01/2010	
21.1	Subsidiaries of Energy Partners, Ltd.					X
23.1	Consent of PricewaterhouseCoopers LLP.					X
23.2	Consent of KPMG LLP.					X
23.3	Consent of Netherland, Sewell & Associates, Inc.					X
23.4	Consent of Ryder Scott Company, L.P.					X
31.1	Certification of Principal Executive Officer of Energy Partners, Ltd. pursuant to Section 302 of the Sarbanes Oxley Act of 2002.					X
31.2	Certification of Principal Financial Officer of Energy Partners, Ltd. pursuant to Section 302 of the Sarbanes Oxley Act of 2002.					X

32.1	Section 1350 Certification of Principal Executive Officer of Energy Partners, Ltd. pursuant to Section 906 of the Sarbanes Oxley Act of 2002.	X
32.2	Section 1350 Certification of Principal Financial Officer of Energy Partners, Ltd. pursuant to Section 906 of the Sarbanes Oxley Act of 2002.	X

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed/ Furnished Herewith
99.1	Report of Independent Petroleum Engineers (Netherland, Sewell & Associates, Inc.) dated as of February 14, 2012					X
99.2	Report of Independent Petroleum Engineers (Ryder Scott Company, L.P.) dated as of February 13, 2012					X
101.INS*	XBRL Instance Document					X
101.SCH*	XBRL Taxonomy Extension Schema Document					X
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document					X
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document					X
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document					X

* In accordance with Rule 406T of Regulation S-T, the XBRL related information in Exhibit 101 to this Annual Report on Form 10-K is furnished and shall not be deemed to be filed for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section, and shall not be part of any registration statement or other document filed under the Securities Act or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

GLOSSARY OF OIL AND NATURAL GAS TERMS

Bbl means one stock tank barrel, or 42 U.S. gallons liquid volume, used in this Annual Report in reference to oil and other liquid hydrocarbons.

Boe means barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

Bcf means one billion cubic feet.

Bcfe means one billion cubic feet equivalent, with one barrel of oil being equivalent to six thousand cubic feet of natural gas.

completion means the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

LOE means lease operating expenditures.

Mbbls means one thousand barrels of oil or other liquid hydrocarbons.

Mboe means one thousand barrels of oil equivalent. 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.

Mcf means one thousand cubic feet of natural gas.

Mmbbls means one million barrels of oil or other liquid hydrocarbons.

Mmboe means one million barrels of oil equivalent.

Mmbtu means one million British Thermal Units.

Mmcf means one million cubic feet of natural gas.

plugging and abandonment means the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Federal regulations and regulations of many states require plugging of abandoned wells.

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

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

working interest means the interest in an oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

PV-10 means the present value of estimated future net revenues computed by applying constant prices, computed in accordance with ASC 932, based on the unweighted, arithmetic average of the closing commodity price on the first day of each of the twelve months during the fiscal year, discounted at a rate of 10% per year on a pre-tax basis.

standardized measure means the present value of estimated future net revenues computed by applying constant prices, computed in accordance with ASC 932, based on the unweighted, arithmetic average of the closing commodity price on the first day of each of the twelve months during the fiscal year, discounted at a rate of 10% per year on a post-tax basis.

sidetrack refers to directional drilling from an existing wellbore to relocate, without having to drill to the depth at which the directional drilling commences, the bottom of the well in a different productive zone that is horizontally removed from the original well.

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SIGNATURES

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

Dated: March 8, 2012

ENERGY PARTNERS, LTD.

By: /s/ GARY C. HANNA
Gary C. Hanna
President and Chief Executive Officer

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

Signature	Title	Date
/S/ GARY C. HANNA **Gary C. Hanna**	President, Chief Executive Officer and Director	March 8, 2012
/S/ TIFFANY J. THOM **Tiffany J. Thom**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 8, 2012
/S/ DAVID P. CEDRO **David P. Cedro**	Senior Vice President, Chief Accounting Officer and Treasurer (Principal Accounting Officer)	March 8, 2012
/S/ CHARLES O. BUCKNER **Charles O. Buckner**	Director	March 8, 2012
/S/ SCOTT A. GRIFFITHS **Scott A. Griffiths**	Director	March 8, 2012
/S/ MARC MCCARTHY **Marc McCarthy**	Director	March 8, 2012
/S/ STEVEN J. PULLY **Steven J. Pully**	Director	March 8, 2012
/S/ WILLIAM F. WALLACE **William F. Wallace**	Director	March 8, 2012

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101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document					X

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