ENERGY PARTNERS LTD
Form 10-K
August 05, 2009
Table of Contents

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, 2008

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 incorporation or organization)	**(I.R.S. Employer Identification No.)**
201 St. Charles Avenue, Suite 3400 New Orleans, Louisiana	**70170**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code:

504-569-1875

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

Title of each class	**Name of exchange on which registered**
Common Stock, Par Value $0.01 Per Share	None

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 ¨ No x

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 ¨ 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. ¨

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

The aggregate market value of the common stock held by non-affiliates of the registrant at June 30, 2009 (the registrant s most recently completed second fiscal quarter) based on the closing stock price as quoted on the Pink Sheets on that date was $9,981,297. As of July 27, 2009, there were 32,286,310 shares of the registrant s common stock, par value $0.01 per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

None

Table of Contents

TABLE OF CONTENTS

Table of Contents

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 in a single segment as an independent oil and natural gas exploration and production company. Our current operations are concentrated in the shallow to moderate-depth waters in the Gulf of Mexico focusing on the areas offshore Louisiana as well as the deepwater Gulf of Mexico at depths less than 5,000 feet. We concentrate on these areas because we believe they provide us with favorable geologic and economic conditions, including multiple reservoir formations, regional economies of scale, extensive infrastructure and comprehensive geologic databases. We believe that these regions offer 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, 2008, we had estimated proved reserves of approximately 90.8 billion cubic feet (Bcf) of natural gas and 21.6 million barrels (Mmbbls) of oil, or an aggregate of approximately 36.8 million barrels of oil equivalent (Mmboe), with a standardized measure of discounted future net cash flows of $416.2 million (see Oil and Natural Gas Reserves for more information about standardized measure of discounted future net cash flows).

Since inception, we had grown our productive property base through a combination of exploration, exploitation and development drilling and multi-year, multi-well drill-to-earn programs, as well as strategic acquisitions of oil and natural gas fields in the shallow to moderate-depth waters in the Gulf of Mexico and in the deepwater Gulf of Mexico and Gulf Coast onshore areas. As we grew our property base, we reduced geographic concentration from three primary producing properties and moved to a more balanced oil and natural gas reserve profile. We also expanded our technical knowledge base through the addition of personnel and geophysical and geological data. Since our highest production levels, which occurred in 2006, production has declined in our core areas and we sold substantially all of our onshore productive properties in 2007 and selected producing properties in the Western offshore area in March of 2008. Our geoscientists and management professionals have considerable Gulf of Mexico and Gulf Coast region-specific geological, geophysical, technical and operational experience. In 2006, we commenced participation in a deepwater exploration program, which resulted in our first deepwater production near the end of 2008.

Recent Events

Filing of Chapter 11 Cases and Preceding Events

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 (the Chapter 11 Cases) under Chapter 11 of Title 11 of the United States Code, 11 U.S.C. §§ 101 et seq., as amended, in the United States Bankruptcy Court for the Southern District of Texas, Houston Division (the Bankruptcy Court). We continue to manage our properties and operate our business as debtors-in-possession under the jurisdiction of the Bankruptcy Court. The Chapter 11 filings were preceded by a number of negative influences and factors, including:

- 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 into early 2009;

- oil and natural gas prices declined in the fourth quarter of 2008 and have remained at relatively low levels during 2009 relative to the levels reached 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 and led to our filing the Chapter 11 Cases, including:

- in the third quarter of 2008, the Minerals Management Service (the MMS) 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, which ultimately led to the March 2009 Incident of Noncompliance and the MMS order to shut-in our production in the federal portion of our East Bay field in March 2009;

- in March 2009, we received a notice of redetermination from Bank of America, N.A., the Administrative Agent under our Credit Agreement dated as of April 23, 2007 (Credit Agreement), that our borrowing base under the Credit Agreement had been reduced from $150 million to $45 million, resulting in a borrowing base deficiency of $38 million which 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 our scheduled interest payments of approximately $17 million on our 9.75% Senior Unsecured Notes due 2014 (the Fixed Rate Notes) and our Senior Floating Notes due 2013 (the Floating Rate Notes and collectively with the Fixed Rate Notes, the Senior Unsecured Notes).

Our inability to satisfy these obligations in a timely manner ultimately led to the filing of the Chapter 11 Cases.

Plan of Reorganization, Exit Facility and Expected Emergence from Bankruptcy

On June 11, 2009, as part of our Chapter 11 Cases, we filed with the Bankruptcy Court our Second Amended Joint Plan of Reorganization (the Plan), and a Second Amended Disclosure Statement (the Disclosure Statement), pursuant to which we solicited votes for the confirmation of the Plan. On July 31, 2009, we filed with the Bankruptcy Court the Plan, as modified as of July 31, 2009. The Plan was formulated after extensive negotiations with committees representing holders of the Senior Unsecured Notes and holders of our common stock interests. The primary purpose of the Plan is to effectuate a restructuring of our capital structure to strengthen our balance sheet by reducing our overall indebtedness and improve cash flow.

On July 23, 2009, we announced that the Plan had received the affirmative vote of the holders of our Senior Unsecured Notes and our 8.75% Senior Notes due 2010 and we consequently proceeded to request confirmation of the Plan from the Bankruptcy Court. On August 3, 2009, after a confirmation hearing in which the Bankruptcy Court considered the Plan and all objections thereto, it entered into a confirmation order (the Confirmation Order) and confirmed the Plan as of August 3, 2009. The effectiveness of the Plan and our emergence from bankruptcy is subject to several conditions, including the successful closing of one or more loans and/or credit facilities that together would provide liquidity to us upon our exit from bankruptcy (together, the Exit Facility). We are currently in negotiations with lenders on structuring the Exit Facility. Fore more information on the conditions to the effectiveness of the Plan see Item 1A Risk Factors.

Delisting

Trading of our common stock was suspended by the New York Stock Exchange (the NYSE) prior to its opening on March 30, 2009 due to our failure to meet the NYSE s continued listing standards regarding average

Table of Contents

global market capitalization. Subsequently, the NYSE delisted our common stock, effective April 27, 2009. Our common stock is currently being quoted for public trading on the Pink Sheets quotations system, an over-the-counter market, under the symbol ERPLQ.PK. Should we emerge from bankruptcy as planned, we anticipate that we will apply for listing for our new common stock on either the NYSE or Nasdaq Global Market (the Nasdaq).

Impact on Current Conduct of Our Business and Management Team

The operation of our business is significantly impacted by our current status as a debtor-in-possession. Our significant strategic activities are generally subject to the approval of the Bankruptcy Court. Our executive management team does not currently include a Chief Financial Officer or Chief Executive Officer. Our Chief Restructuring Officer has been engaged primarily to focus on our financial restructuring and the Chapter 11 Cases. We expect that our ownership and Board of Directors will change as a result of the financial restructuring. As part of the Plan, we have filed with the Bankruptcy Court the names of several persons who will be among our board members after we emerge from bankruptcy. We do not have any information, however, about any plans for the conduct of our business that our potential post-bankruptcy stockholders may have or that any future directors or executive management may implement, and we cannot predict what those plans might be. You can find more information on the Plan and the recent events that have impacted us under Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Recent Events.

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*.

Capital Expenditures in 2009

Our exploration and development expenditures for 2008 totaled $205.1 million. We expect that our exploration and development activities in 2009 will be significantly lower than in prior years in order to conserve cash resources. For 2009, we expect exploration and development expenditures to total less than $10 million, which we expect would be directed primarily toward selective efforts to stabilize existing production levels. Our plans for 2009 do not include any acquisitions or deepwater activities. Our lease portfolio is primarily located offshore in the Gulf of Mexico and includes a mixture of lower risk development and exploitation opportunities, moderate risk exploration opportunities and higher risk, higher potential exploration projects.

Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations contains important information about events that had a material impact on our business in 2008 and that we expect will continue to materially impact our business in 2009.

Table of Contents

Our Properties

As of December 31, 2008, we had working interests in 24 producing fields, primarily located in the Gulf of Mexico region. These fields fall into five areas which we identify and describe more completely below as:

- Eastern offshore comprised primarily of one producing field, our East Bay field;
- Central offshore comprised of four producing fields, all of which are located in close proximity to each other and are in the vicinity of the Bay Marchand salt dome;
- Deepwater Gulf of Mexico comprised of 22 offshore blocks, including one well at Mississippi Canyon Block 248 that was producing at December 31, 2008;
- Western offshore comprised of 15 producing fields extending from offshore central and western Louisiana to Texas; and
- Gulf Coast onshore and other located in South Louisiana and Texas.

The Eastern and Central offshore fields and the acreage surrounding them comprise the core of our property base and the focus of our near term efforts. Over the last several years, we added to our leasehold acreage position in these areas through federal and state lease sales, acquisitions and trades with industry partners.

Eastern Offshore Area

East Bay, the key asset in our Eastern offshore area, comprised approximately 21% of our production during 2008 and 37% of our proved reserves at the end of 2008, and is located 89 miles southeast of New Orleans near the mouth of the Mississippi River. It contains producing wells located onshore along the coastline and in water depths ranging up to approximately 170 feet and is comprised primarily of the South Pass 24, 26 and 27 blocks. We operate this field and own an average 97% interest in our acreage position in this area.

Our leasehold area covered 42,434 gross acres (41,141 net acres) as of December 31, 2008. See Recent Events in Part II, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations for important information about our East Bay leases.

Central Offshore Area

These fields, located in the Greater Bay Marchand area, comprised approximately 46% of our production during 2008 and 43% of our proved reserves at the end of 2008. The core assets of our Central offshore area are located approximately 60 miles south of New Orleans in water depths of 181 feet or less. Our key assets in this area include the South Timbalier 26, 41 and 46 and Bay Marchand fields.

In 2003, we drilled our initial discovery well in the South Timbalier 41 field, in which we hold a 60% working interest, on acreage acquired earlier that year in a federal lease sale. Several exploratory and development wells have been drilled in the field and all but one well has been brought on production. This field, which has additional reserve potential, represents the most significant discovery in our history. We acquired acreage in additional leases in the vicinity of this field in 2005 and subsequent years.

In addition, at the beginning of 2005 we owned a 50% interest in the South Timbalier 26 field. In March 2005, we closed the acquisition of the remaining 50% interest in South Timbalier 26 above approximately 13,000 feet subsea. As a result of the acquisition, we own a 100% interest in the producing horizons in this field. The acquisition expanded our interest in our core Greater Bay Marchand area and gave us additional flexibility in undertaking the future development of the South Timbalier 26 field. In 2008, we closed on the acquisition of the primary lateral natural gas production pipeline serving our South Timbalier 26 field.

4

Table of Contents

Deepwater Gulf of Mexico Area

During 2008, we closed the acquisition of our leasehold interest in Mississippi Canyon 292, including one well that was drilled in 2007 under our farmout agreement with the prior owner. We also entered into a production handling agreement with the prior owner for production facilities located in the Mississippi Canyon 292 field, allowing us to begin producing our Mississippi Canyon 248 well beginning in November 2008. Our Mississippi Canyon 204 well was drilled in 2006. At December 31, 2008, we owned interests in 22 blocks in the deepwater Gulf of Mexico area. Our working interests in our leases in this area range from 15% to 33%. We have additional prospects identified on our deepwater acreage portfolio. See Results of Operations in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 1A, Risk Factors for important information about risks related to our ownership of the deepwater Gulf of Mexico properties.

Western Offshore Area

The properties in the Western offshore area are located in water depths ranging from 7 to 272 feet with working interests ranging from 20% to 100%. In March 2008, we completed the sale of two Gulf of Mexico Shelf properties located in our Western offshore area. We owned interests in 15 producing fields in this area at December 31, 2008.

Gulf Coast Onshore and Other Areas

In 2005, we closed an acquisition of properties and reserves onshore in south Louisiana for $149.6 million in cash, after adjustments. In June 2007, we sold substantially all of our onshore South Louisiana producing assets for approximately $68.6 million after closing adjustments. The remaining properties in these areas are located in south Louisiana and the Permian area in Texas with working interests ranging from 15% to 40% and are comprised of undeveloped acreage with three wells producing at year end.

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, 2008, 2007 and 2006. Our estimates of proved reserves are based on reserve reports prepared by Netherland, Sewell & Associates, Inc. and Ryder Scott Company, L.P., independent petroleum engineers as of December 31, 2008. Neither the present values, discounted at 10% per year, of estimated future net cash flows before income taxes (PV-10), or the standardized measure of discounted future net cash flows shown in the table are intended to represent the current market value of the estimated oil and natural gas reserves that we own. Note 20 Supplementary Oil and Natural Gas Disclosures to 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.

PV-10 may be 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. While the standardized measure is dependent on the unique tax situation of each company, and our calculation of PV-10 may therefore not be comparable to those of our competitors, PV-10 is based on estimated oil and natural gas selling prices and discount factors that are consistent for all companies. 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.

Table of Contents

	2008	As of December 31, 2007 (dollars in thousands)	2006
Total estimated net proved reserves (1):			
Oil (Mbbls)	21,637	28,123	29,914
Natural gas (Mmcf)	90,808	103,118	170,123
Total (Mboe)	36,771	45,309	58,268
Net proved developed reserves (2):			
Oil (Mbbls)	17,052	23,636	24,811
Natural gas (Mmcf)	79,413	85,926	117,392
Total (Mboe)	30,288	37,957	44,376
Estimated future net revenues before income taxes (3)	$ 557,660	$ 2,172,162	$ 1,632,470
Present value of estimated future net revenues before income taxes (3) (4)	$ 425,247	$ 1,470,285	$ 1,188,295
Standardized measure of discounted future net cash flows (5)	$ 416,171	$ 1,092,935	$ 893,474

(1) Approximately 68% of our total proved reserves were proved developed non-producing and proved undeveloped at December 31, 2008.

(2) Net proved developed non-producing reserves as of December 31, 2008 (9,127 Mbbls and 55,844 Mmcf) were 18,434 Mboe, or 50% of our total proved reserves.

(3) The December 31, 2008 amount was calculated using a period-end oil price of $44.77 per barrel and a period-end natural gas price of $6.05 per Mcf. The December 31, 2007 amount was calculated using a period-end oil price of $94.76 per barrel and a period-end natural gas price of $6.98 per Mcf. The December 31, 2006 amount was calculated using a period-end oil price of $58.40 per barrel and a period-end natural gas price of $5.54 per Mcf.

We believe estimated future net revenues before income taxes and present value of estimated future net revenues before income taxes are important measures for evaluating our natural gas and oil properties. Because of factors which may impact the amount of future income taxes that are unique to us and/or unique to other companies to which we might be compared, we believe the use of pre-tax measures provides greater comparability of these measures.

(4) The present value of estimated future net revenues attributable to our reserves was prepared using constant prices, as of the calculation date, discounted at 10% per year on a pre-tax basis.

(5) 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.

Costs Incurred in Oil and Natural Gas Activities

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

	2008	Years Ended December 31, 2007 (In thousands)	2006
Acquisitions:			
Proved	$	$ 2,167	$ 420
Unproved	20,925	7,346	15,896
Exploration	56,202	191,621	224,147
Development (1)	127,948	121,769	167,346

Costs incurred	$ 205,075	$ 322,903	$ 407,809

(1) Includes asset retirement obligations incurred of $13.4 million, $5.6 million and $8.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Table of Contents

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, 2008.

	Total Productive Wells	
	Gross	Net
Oil	205	155
Natural gas	63	33
Total	268	188

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

In this Annual Report, gross refers to the total wells in which we have a working interest and net refers to gross wells multiplied by our working interest in the wells.

Acreage

The following table sets forth information as of December 31, 2008 relating to acreage held by us. Developed acreage is assigned to producing wells.

	Gross Acreage	Net Acreage
Developed:		
Eastern offshore area	30,341	29,047
Central offshore area	26,187	16,937
Western offshore area	69,982	45,117
Deepwater Gulf of Mexico area	5,760	1,920
Gulf Coast onshore area	960	224
Total	133,230	93,245
Undeveloped:		
Eastern offshore area	12,093	12,093
Central offshore area	70,525	69,666
Western offshore area	152,287	128,083
Deepwater Gulf of Mexico area	126,720	33,503
Gulf Coast onshore and other area	15,944	1,703
Total	377,569	245,048

Leases covering 12% of our undeveloped net acreage expire in 2009, 32% in 2010, 24% in 2011, 7% in 2012, 18% in 2013 and 7% thereafter. See Results of Operations in Part II, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations for important information about our undeveloped acreage.

7

Table of Contents

Drilling Activity

The following table shows our well activity for the years ended December 31, 2008, 2007 and 2006.

	Years Ended December 31,					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	13.0	10.6	4.0	2.6	3.0	1.7
Non-productive						
Total	13.0	10.6	4.0	2.6	3.0	1.7
Exploration Wells:						
Productive	3.0	0.7	11.0	6.0	17.0	8.7
Non-productive	1.0	0.2	11.0	8.3	6.0	2.7
Total	4.0	0.9	22.0	14.3	23.0	11.4

Drilling activity refers to the number of wells completed at any time during the fiscal years, regardless of when drilling was initiated. For purposes of this table, the term completed refers to the installation of permanent equipment for the production of oil or natural gas. See Results of Operations in Part II, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations for important information about our suspended wells that were under evaluation as of December 31, 2008.

Title to Properties

Our properties are subject to customary royalty interests, liens under indebtedness, liens incident to operating agreements, mechanics and materialman 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 in 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.

The MMS, in its order dated March 23, 2009, required us to immediately shut-in production from all of our wells and facilities located in the federal portion of our East Bay field in South Pass Blocks 27 and 28. On April 30, 2009, we entered into a binding term sheet with the MMS to establish terms to address our obligations to the MMS related to plugging and abandonment liabilities associated with all of our federal properties in the Gulf of Mexico, with which we complied. The section Recent Events in Part II, Item 7, Managements Discussion and Analysis of Financial Condition and Results of Operations of this Annual Report contains additional information about our obligations to the MMS and the risks to our offshore leases resulting from those obligations.

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 (the FERC) as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the tests the FERC has historically 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 services and federally unregulated gathering services is the subject of substantial, 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 may 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 various safety, environmental, nondiscriminatory take, and common purchaser requirements, and complaint-based rate regulation.

The gathering systems are also subject to the jurisdiction of the MMS, since they traverse the OCS pursuant to MMS-issued easements. The MMS issued a final rule, effective August 18, 2008, that implements a hotline, alternative dispute resolution procedures, and complaint procedures for resolving claims of having been denied open and nondiscriminatory access to pipelines on the OCS. We cannot predict the ultimate impact of these regulatory changes to our OCS natural gas operations. We do not believe that we would be affected by any such regulatory changes materially differently than other gathering lines operating on the OCS with whom we compete.

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 as natural gas companies under the NGA, our gathering facilities may be subject to certain FERC annual natural gas transaction reporting requirements and daily scheduled flow and capacity posting requirements depending on the volume of natural gas transactions and flows in a given period. See the discussion of Other Federal Laws and Regulations Affecting Our Industry FERC Market Transparency Rules.

Table of Contents

In 2007, Texas enacted new laws regarding rates, competition and confidentiality for natural gas gathering and transmission pipelines (the Competition Statute) and new informal complaint procedures for challenging determinations of lost and unaccounted for gas by gas gatherers, processors and transporters (the LUG Statute). The Competition Statute gives the Railroad Commission of Texas (the RRC) the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering and intrastate transportation pipelines in formal rate proceedings. This statute also gives the RRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in an informal complaint process and to punish purchasers, transporters, and gatherers for taking discriminatory actions against shippers and sellers. The Competition Statute also provides producers with the unilateral option to determine whether or not confidentiality provisions are included in a contract to which a producer is a party for the sale, transportation, or gathering of natural gas. The LUG Statute modifies the informal complaint process at the RRC with procedures unique to lost and unaccounted for gas issues. Such statute also extends the types of information that can be requested, provides producers with an annual audit right, and provides the RRC with the authority to make determinations and issue orders in specific situations. Both the Competition Statute and the LUG Statute became effective September 1, 2007. We cannot predict what effect, if any, these statutes might have on our future operations in Texas.

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 Futures Trading Commission (the 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, pursuant to Order 704 (as defined below) some of our operations may be required to annually report to the FERC, starting May 1, 2009, information regarding natural gas purchase and sale transactions depending on the volume of natural gas transacted 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 is continually proposing and implementing 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 materially differently 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. The FERC strongly encouraged all natural gas pipelines subject to its jurisdiction to adopt, as needed, gas quality and interchangeability standards in their FERC gas tariffs modeled on the interim guidelines issued by a group of industry representatives, headed by the Natural Gas Council (the NGC+ Work Group), or to explain how and why their tariff provisions differ. We do not believe that the adoption of the NGC+ Work Group s gas quality interim guidelines by a pipeline that either directly or indirectly interconnects with our facilities would materially affect our operations. We have no way to predict, however, whether FERC will approve of gas quality specifications that materially differ from the NGC+ Work Group s interim guidelines for such an interconnecting pipeline.

Table of Contents

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, or 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 Domenici-Barton Energy Policy Act of 2005 (the 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, the EPAct 2005 amended the NGA and the Natural Gas Policy Act of 1978, as amended (the NGPA), by increasing the criminal penalties available for violations of each Act. The EPAct 2005 also added a new section to the NGA, which provides the FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and $1,000,000 per violation per day for violations of the NGPA. 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 which makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by the FERC. In 2006, the FERC issued Order No. 670 (Order 670) to implement the anti-market manipulation provision of EPAct 2005. Order 670 makes 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 person. Order 670 does 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 under Order 704 (as defined below) and the daily scheduled flow. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of the FERC s NGA enforcement authority.

FERC Market Transparency Rules. In 2007, the FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing (Order 704). Under Order 704, 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 are now required to report, on May 1 of each year, beginning in 2009, 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. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704.

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 FERC action materially differently than other natural gas companies with whom we compete.

Table of Contents

Environmental Regulations

General. Various federal, state and local laws and regulations governing the protection of the environment, such as 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;
- limit or prohibit drilling and production activities on certain lands lying within wilderness, wetlands and other protected areas;
- impose permitting, monitoring, and recordkeeping requirements and other regulatory controls; and
- impose substantial liabilities for pollution resulting from our operations, including the performance of remedial measures to address pollution as a result of operations.

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. Changes in environmental laws and regulations occur regularly, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position and the oil and natural gas industry in general. While we believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on us, there is no assurance that this trend will continue in the future.

As within the industry generally, compliance with existing laws and regulations increases our overall cost of business. The areas affected include:

- unit production expenses primarily related to the control and limitation of air emissions and the disposal of produced water;
- capital costs to drill exploration and development wells primarily related to the management and disposal of drilling fluids and other oil and natural gas exploration wastes; and
- capital costs to construct, maintain and upgrade equipment and facilities.

Superfund. CERCLA, also known as Superfund, imposes liability for response costs associated with releases of hazardous substances and damages to natural resources as a result of such releases, without regard to fault or the legality of the original act, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. 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. CERCLA also 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 the responsible classes of persons the costs they incur in remediating releases of hazardous substances. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. The term hazardous substance does not include petroleum, including crude oil or any fraction thereof, unless specifically listed or designated under CERCLA, and the term does not include natural gas, NGLs, liquefied natural gas, or synthetic gas usable for fuel. While this petroleum exclusion lessens the significance of

CERCLA to our operations, in the course of our ordinary operations, we may generate waste that may fall within CERCLA s definition of a hazardous substance. We may be jointly and severally liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these wastes have been disposed.

Table of Contents

We currently own or lease properties that for many years have been used for the exploration and production of oil and natural gas. Although we and our predecessors have used operating and disposal practices that were standard in the industry at the time, hazardous substances may have been disposed or released on, under or from the properties owned or leased by us or on, under or from other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose actions with respect to the treatment and disposal or release of hazardous substances were not under our control. These properties and wastes disposed on these properties could give rise to liability under CERCLA and analogous state laws. Under these laws, we could be required:

- to remove or remediate previously disposed wastes, including wastes disposed or released by prior owners or operators;
- to clean up contaminated property, including contaminated groundwater;
- to pay for natural resource damages resulting from the releases;
- to perform certain health studies; or
- to perform remedial operations to prevent future contamination.

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.

Oil Pollution Act of 1990. The Oil Pollution Act of 1990, as amended (the OPA), and regulations thereunder impose liability on responsible parties for damages resulting from oil spills into or upon navigable waters, adjoining shorelines, or in the exclusive economic zone of the United States. A responsible party includes the owner or operator of an onshore facility and the lessee or permittee of the area in which an offshore facility is located. OPA also requires the lessee or permittee of the offshore area in which a covered offshore facility is located to 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 financial responsibility and other operating requirements will not have a material adverse effect on us.

Resource Conservation and Recovery Act. RCRA provides a framework for the disposal of discarded materials and the management of solid and hazardous wastes. RCRA imposes stringent waste management requirements, and liability for failure to meet such requirements, on a person who is either a generator or transporter of hazardous waste or an owner or operator of a hazardous waste treatment, storage or disposal facility. 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 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 produced water and other wastes into navigable 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 developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for oil and other pollutants or unauthorized discharges of fill material into wetlands or other waters and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release, for natural resource damages resulting from the release, and for mitigation or restoration related to the filling of wetlands and other waters. 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, and Endangered Species Act. Certain federal laws, including the National Marine Sanctuaries Act and the Marine Mammal Protection Act provide special protection to certain designated marine areas and marine species. 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, MMS 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 MMS 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. The MMS has issued numerous NTLs relating to the prevention of harm to marine species, with which we must comply. In addition, certain plants and animals have been classified as threatened or endangered and are protected under the Endangered Species Act (the ESA). The ESA prohibits the take, including harm or harassment, of these protected species and damage to their habitat. If endangered 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.

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 MMS to ensure worker safety during paint removal.

Table of Contents

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 require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and 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 these 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 requirements.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere. In response to such studies, the U.S. Congress is considering legislation to reduce emissions of greenhouse gases. President Obama has expressed support for legislation to restrict or regulate emissions of greenhouse gases. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Depending on the particular program, we could be required to purchase and surrender allowances for greenhouse gas emissions resulting from our operations, prepare an inventory of greenhouse gas emissions resulting from our operations, or pay a tax on the greenhouse gas emissions resulting from our operations. These requirements could increase our operational and compliance costs and result in reduced demand for the oil and natural gas we produce.

Also, as a result of the United States Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may regulate greenhouse gas emissions from mobile sources such as cars and trucks even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court s holding in *Massachusetts* that greenhouse gases including carbon dioxide fall under the federal Clean Air Act s definition of air pollutant may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources. In July 2008, the EPA released an Advance Notice of Proposed Rulemaking regarding possible future regulation of greenhouse gas emissions under the Clean Air Act in response to the Supreme Court s decision in *Massachusetts*. In the notice, the EPA evaluated the potential regulation of greenhouse gases under the Clean Air Act and other potential methods of regulating greenhouse gases. Although the notice did not propose any specific, new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. In March 2009, the EPA proposed a comprehensive national system for reporting emissions of greenhouse gases for major sources of emissions. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such new federal, regional or state restrictions on emissions of carbon dioxide or other greenhouse gases that may be 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.

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.

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 MMS and are required to comply with the regulations and orders promulgated by the MMS under OCSLA.

Recently, the MMS announced that it will 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 MMS granted approval to operators to maintain these structures in order to conduct other future activities; however, we expect that this practice will be more limited in the future. The MMS has stated that these measures are in response to the experiences in recent hurricane seasons with damage caused by idle structures. In 2008, we responded to an MMS 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. As a result, we reviewed a plan with the MMS to perform wellbore plugging and abandonment and decommissioning work on certain facilities and structures in our East Bay field during 2009, 2010 and 2011.

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 Outer Continental Shelf. The effects included structural damage to fixed production facilities, semi-submersibles and jack-up drilling rigs. The MMS continues to be concerned about the loss of these facilities and rigs as well as 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 MMS issued 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 MMS for the 2009 hurricane season. These new requirements could increase our operating costs. The MMS 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 affect 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 MMS could require us to suspend or terminate our operations on a federal lease. 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 the oil and natural gas from properties we operate and from properties others operate where our interest is significant. We sell our natural gas to marketing companies pursuant to a variety of contractual arrangements, generally under contracts with terms no longer than seven 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. All 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 2008, Shell Trading (US) Company accounted for approximately 38%, Louis Dreyfus Energy Services, L.P. accounted for approximately 24% and ChevronTexaco Exploration & Production Company accounted for approximately 23%. 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 operation, although a temporary disruption in production revenues could occur.

[Table of Contents](#)

Employees

As of December 31, 2008, we had 156 full-time employees, including 28 geoscientists, engineers and technicians and 64 field personnel. As of June 30, 2009, we had 117 full-time employees. 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.

As a result of the uncertainties related to our current financial condition, we have lost 39 employees through lay-offs and voluntary departures during the first half of 2009. 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 accounting functions.

Competitors

Our competitors include numerous independent oil and gas companies, individuals 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. We expect the significant decline in commodity prices that occurred in the latter part of 2008, along with a general economic downturn, generally to create downward pressure in 2009 on prices for the materials and services that we use in our operations, primarily our exploration, development and abandonment activities, though the duration and extent of expected price declines is highly uncertain.

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 to recent lows 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 abandonment activities, which can delay our operations, increase the cost of our operations and/or delay the restoration and maintenance of our oil and natural gas production.

Cautionary Statement Concerning Forward Looking Statements

This Annual Report contains certain forward-looking statements within the meaning of Section 21E of the Exchange Act. When used herein, the words will, would, should, likely, estimates, thinks, strives, may, anticipates, expects, believes, intends, goals, plan expressions are

Table of Contents

intended to identify forward-looking statements, which are generally not historical in nature. While our management considers the expectations and assumptions to be reasonable when and as made, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks, contingencies and uncertainties relate to, among other matters, the following:

- our inability to continue business operations during the Chapter 11 proceedings;
- our ability to consummate the Plan as currently planned and risks associated with negotiating and closing the Exit Facility;
- the potential adverse effects of the Chapter 11 Cases on our liquidity and results of operations;
- our ability to retain, recruit and motivate key executives and other necessary personnel while seeking to implement the Plan;
- our ability to continue as a going concern;
- changes in general economic conditions;
- uncertainties in reserve and production estimates;
- unanticipated recovery or production problems;
- hurricane and other weather-related interference with business operations;
- the effects of delays in completion of, or shut-ins of, gas gathering systems, pipelines and processing facilities;
- oil and natural gas prices and competition;
- the impact of derivative positions;
- production expense estimates;
- cash flow estimates;
- future financial performance;

- planned capital expenditures; and

- other matters that are discussed in our filings with the SEC.

These statements are based on current expectations and projections about future events and involve known and unknown risks, uncertainties, and other factors that may cause actual results and performance to be materially different from any future results or performance expressed or implied by these forward-looking statements. Investors are cautioned that all such statements involve risks and uncertainties. Our actual decisions, performance and results may differ materially. Important trends or factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to, those described in the section 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.

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 paragraph 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 Relating to Energy Partners, Ltd.

We are currently in proceedings under Chapter 11 of the Bankruptcy Code. There is no guarantee that we will successfully emerge from bankruptcy. As part of our bankruptcy proceedings we are negotiating the Exit Facility but there is no guarantee that we will be able to successfully close the Exit Facility. If we are unable to successfully complete the Chapter 11 proceedings or close the Exit Facility, we may be forced to liquidate.

We are currently in proceedings under Chapter 11 of the Bankruptcy Code. While the Plan was approved by the Bankruptcy Court on August 3, 2009, our emergence from bankruptcy is subject to several conditions, including the successful closing of the Exit Facility, and there is no guarantee that we will successfully emerge from bankruptcy. We cannot predict the timing of the Chapter 11 proceedings and undue delays in the proceedings may disrupt our operations. If we are unable to complete the Chapter 11 proceedings in a timely manner, we may be required to liquidate.

One of the conditions to effectiveness of the Plan is the closing of the Exit Facility. We must obtain, consummate and close the Exit Facility in order to emerge from bankruptcy. If we are unable to successfully negotiate definitive documentation for the Exit Facility or unable to satisfy the conditions to closing of the Exit Facility, we would be unable to consummate the Plan and may consequently have to liquidate. Under the Confirmation Order, if we are unable to successfully comply with all conditions to the Plan by the later of (1) September 10, 2009, (2) September 25, 2009, with our approval and the approval of the Majority Consenting Holders (as defined below), or (3) any later date approved by the Bankruptcy Court, the Confirmation Order will be vacated and we will not be able to proceed with the execution of the Plan, as planned.

We faced significant liquidity challenges in 2009 that led to our Chapter 11 filings and could have ongoing material and adverse effects on our business operations even after we emerge from bankruptcy.

Largely as a result of the shut-in of a significant amount of our production from September 2008 into early 2009 following Hurricanes Ike and Gustav, and the dramatic decline in oil and natural gas prices that started in the third quarter of 2008, we face significant liquidity challenges, which led to our Chapter 11 filings. Many current economic forecasts portray a dismal outlook for the oil and natural gas exploration and development business for at least a significant portion of 2009 due to low and volatile oil and natural gas prices, coupled with a global recession that is projected to be long and severe. If prices continue at the current low levels, our anticipated investment will not be adequate to maintain our current production levels and we expect our production to decline significantly during the second half of 2009 due primarily to natural reservoir declines combined with minimal investment in reserve replacement activities. At our current and anticipated production levels, combined with the current and expected lower prices, we do not expect to have sufficient cash flows to fund our operations and meet our 2009 financial obligations as they existed prior to the filing of the Chapter 11 Cases. As a result, we will continue to experience a decline in our revenues and available capital, which will substantially decrease our capital expenditures, drilling activities and operations.

Even if we successfully enter into the Exit Facility and emerge from bankruptcy, we will continue to have substantial capital needs which may not be available in the future.

Assuming the Exit Facility is available and we successfully emerge from bankruptcy, we will continue to have substantial capital requirements to fund our business. We may not be able to generate sufficient cash flow from operations to meet our debt payment obligations, which cash flows will be subject to a range of economic, competitive and business risk factors. Additionally, the amounts available under the Exit Facility may not be sufficient for our capital requirements and we may not be able to access additional financing resources due to a variety of reasons, including restrictive covenants in the Exit Facility and the lack of available capital due to the tightening of the global credit markets. If we are unable to make scheduled payments on the Exit Facility, or if our financing requirements are not met by the Exit Facility and we are unable to access additional financing, our business, operations, financial condition and cash flows will be negatively impacted.

No established trading market exists for the common stock we anticipate issuing upon our emergence from bankruptcy, and if one develops, it may not be liquid.

No established trading market exists for the common stock we anticipate issuing upon our emergence from bankruptcy, and there is no assurance that any active trading market will develop for it. Our existing common stock has been delisted from the NYSE. Upon or as soon as practicable following our emergence from bankruptcy, we intend to apply for the listing of our new common stock on the NYSE or another national stock exchange, such as the Nasdaq, assuming we satisfy the applicable listing criteria. There is no assurance that the NYSE or any other national exchange will approve our new common stock for listing as there is no assurance that we will satisfy the criteria for listing, or be approved for listing, on the NYSE or another national stock exchange. Failure to list our new common stock will negatively affect the ability of our shareholders to sell their shares.

We do not anticipate paying dividends on our common stock in the foreseeable future.

We do not anticipate paying any dividends in the foreseeable future. In addition, the covenants in certain debt instruments to which we anticipate being a party, including the Exit Facility, will likely place restrictions or conditions on our ability to pay dividends. Certain institutional investors may only invest in dividend-paying equity securities or may operate under other restrictions that may prohibit or limit their ability to invest in us.

Failure to maintain compliance with the listing standards of the NYSE has resulted in the delisting of our common stock.

On March 24, 2009, NYSE Regulation, Inc. provided us with a written notice that trading of our common stock would be suspended from trading prior to the NYSE s opening on March 30, 2009. The notice stated that we were not in compliance with NYSE s continued listing standards, which currently require a company with common stock listed on the NYSE to maintain an average global market capitalization of not less than $15.0 million over a consecutive 30 trading-day period. The NYSE suspended trading of our common stock prior to the market opening on March 30, 2009. On April 15, 2009, the NYSE filed a Form 25 with the SEC notifying the SEC of the delisting of our common stock, which became effective on April 27, 2009.

Our common stock is being quoted for public trading on the Pink Sheets quotations system, an over-the-counter market, under the symbol ERPLQ.PK. Recently, our common stock has traded at low prices and we have experienced a significant decline in market capitalization. Delisting from the NYSE could continue to adversely affect the trading price of our common stock, significantly limit the liquidity of our common stock and impair our ability to raise additional equity financing. The limitations on trading possibilities for our investors resulting from our delisting from a national exchange may further negatively impact the liquidity of our stock.

Under the terms of the Plan, each holder of (1) our Senior Unsecured Notes and our 8.75% Senior Notes due 2010 would receive, in exchange for their total claim (including principal and interest), their pro rata share of 95% and (2) each holder of our common stock interests would receive, in exchange for their total claim, their pro rata share of 5% of our common stock to be issued pursuant to the Plan upon our emergence from bankruptcy. Following the reorganization, the sole equity interests in the reorganized company would consist of (1) new EPL common stock issued to the holders of the Senior Unsecured Notes, the 8.75% Senior Notes due 2010, and the holders of common stock, (2) restricted new EPL common stock issued to certain members of management of the reorganized company, if any, and (3) new EPL stock options to be issued to certain key employees pursuant to the 2009 Long Term Incentive Plan, if any, which would be exercisable for new EPL common stock. Collectively, the restricted new EPL common stock issued pursuant to subparagraph (2) and the shares reserved for the exercise of new EPL stock options pursuant to subparagraph (3) above would in no event exceed 3% of the new EPL common stock on a fully diluted basis.

Our credit ratings have been reduced and withdrawn and failure to regain and improve our credit ratings could have a material adverse effect on our business.

Moody s Investors Service recently downgraded each of our Corporate Family Rating, Probability of Default Rating and our Senior Unsecured Notes Rating to default levels or equivalent and announced that it would withdraw its ratings due to the Chapter 11 proceedings. The decline and withdrawal of our credit ratings reflects concerns over our financial strength. Our current credit ratings status reduces our access to the debt markets and will unfavorably impact our overall cost of borrowing.

The MMS may shut in production on the outer shelf in connection with our failure to provide cash or other adequate security to secure our obligations to plug, abandon and decommission our wellbores and related pipelines and facilities.

Most of our offshore operations are conducted on federal leases that are administered by the MMS and we are required to comply with the regulations and orders promulgated by the MMS under OCSLA. Among other things, MMS regulations establish construction and safety requirements for production facilities located on our federal offshore leases and govern the plugging and abandonment of wells and the operation, maintenance, and removal of production facilities from these leases.

On March 5, 2009, we were notified by the MMS that an Incident of Noncompliance (INC) had been issued as a result of our failure to provide supplemental bonds or other security in the amount of $16.7 million that was due by February 27, 2009 to guarantee performance of our obligations to abandon wells, remove platforms and facilities, and clear the seafloor of obstructions on leases with associated lease obligations. The INC stated that our failure to correct this INC by the close of business on March 27, 2009 would result in a shut-in of our outer continental shelf facilities associated with South Pass Block 27 and South Pass Block 28 that are located in federal waters, which payment we informed the MMS we could not make by the March 27 deadline. We received an order from the MMS dated March 23, 2009. The March 23, 2009, order required, among other financial requirements, that we immediately shut-in production from all of our wells and facilities located in South Pass Blocks 27 and 28 in the federal portion of our East Bay field, while properly maintaining these facilities and wells with essential personnel. We promptly completed the shut-in of our federal East Bay facilities before the end of March 2009. Because federal leases would normally terminate if there is no production for 180 consecutive days, the affected leases could expire if (1) we do not comply with the requirements set forth by applicable MMS regulations and restore production to the shut-in federal leases by September 17, 2009; (2) we and the MMS do not otherwise come to an agreement that would prevent the leases from expiring on such date; or (3) there is no unitized production that would prevent the termination provisions in the affected leases from being triggered. The federal East Bay leases are included in production unit(s) covering portions of those leases and state leases in the East Bay field that continue to produce, which we believe may prevent the triggering of lease termination, although there is no assurance that this will be the case. The continued shut down of these facilities and, should it occur, the resulting termination of the related leases would have a material adverse effect on our financial position, results of operations and cash flows.

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations which are addressed under Part I, Item 1, Business Environmental Regulations in this Annual Report.

We have been requested to provide additional reserves with respect to our outstanding surety bonds.

In December 2008 and the first quarter of 2009 we posted cash collateral to restricted accounts for the benefit of two of our indemnity companies totaling $5.7 million in response to requests by them to provide reserves against our surety bonds with them. Our agreements with these indemnity companies allow them to demand cash reserves or letters of credit to support our outstanding surety bonds. As of July 1, 2009, we had outstanding $60.0 million in surety bonds with four different indemnity companies. During 2009, our indemnity companies have requested additional reserves with respect to these outstanding surety bonds, and we do not have the cash or borrowing capacity to comply with these requests. As a result, we will default on some or all of these agreements and the indemnity companies may cancel our surety bonds. The cancelation of some or all of our surety bonds may result in violations of other agreements or obligations. As a result, we could be forced to shut in our production or lose our ability to continue to perform our business operations.

Our current financial condition has adversely affected our business operations and our business prospects.

Our current financial condition and resulting uncertainty have been disruptive to our business. Management has devoted substantial time and attention to improving our financial condition, thereby reducing its focus on operating the business. In addition, as a result of the uncertainties related to our current financial condition, we have lost 39 employees through lay-offs and voluntary departures during the first half of 2009. These employee losses may negatively impact employee morale and productivity and continue to cause voluntary employee resignations. Further, our current financial condition and resulting uncertainty may cause operating partners to terminate their relationships with us or to tighten credit. These developments could have a material adverse effect on our business, operations, financial condition and cash flows.

Our asset carrying values have been impaired based, in part, on oil and natural gas prices as of December 31, 2008 and they may be further impaired if oil and gas prices continue to decline from prices in effect as of that date.

The substantial decline in oil and gas prices and reduced capital spending on certain fields based on this lower price environment in 2008 and continuing in 2009 has impacted the estimated net cash flows from our oil and natural gas reserves, which estimates are used to determine impairments of our oil and natural gas properties. As a result of the decline in oil and gas prices, we have revised our estimated reserves downward and have significantly reduced our estimated future cash flows. Based in part on our 2008 year-end estimates of proved reserves, we recorded a non-cash pre-tax impairment charge of $108.6 million in the fourth quarter of 2008. We may be required to recognize additional non-cash pre-tax impairment charges in future reporting periods if market prices for oil or natural gas continue to decline or based on other factors, including our ability to fund capital expenditures required to maintain our oil and natural gas reserves.

Our current operations are concentrated in the Gulf of Mexico, and a significant part of the value of our production and reserves is concentrated in two geographic areas. 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.

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.

During 2008, 46% of our net daily production came from our Greater Bay Marchand properties and approximately 43% of our proved reserves were located in the fields that comprise this area. In addition, 21% of our net daily production came from our East Bay field and approximately 37% of our proved reserves were located on this property. 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 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 and the Gulf Coast 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 primarily all of our operations are concentrated in the Gulf of Mexico and 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, 2008, our independent petroleum engineers estimate that, on average, 65% of our total proved reserves will be produced within five years. We may not be able to develop, exploit, find or acquire additional reserves to sustain our current production levels or to grow our production. In addition, we have substantially cut our planned capital expenditures for 2009 in order to conserve cash resources, which will likely negatively impact our ability to replace existing reserves lost as a result of production. There can be no assurance that we will be able to grow production at rates we have experienced in the past. Our future oil and natural gas reserves and production, results of operations and cash flows are highly dependent on our ability to efficiently develop and exploit our current reserves and economically find or acquire additional recoverable reserves.

Our exploration, exploitation and production operations in the deepwater Gulf of Mexico area present unique operating risks.

The deepwater Gulf of Mexico area is an area that 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, including:

- an extended length of time between drilling and first production as compared to typical shallow to moderate-water depth projects;
- drilling that requires specific types of rigs with significantly higher day rates and limited availability as compared to the rigs used in shallow water;
- more costly consequences of mechanical failure because of the equipment required to operate at the water depths and adverse conditions found in the deepwater Gulf of Mexico area;
- mechanical risks because the wellhead equipment is installed on the sea floor;
- many reservoirs are sub-salt and are more difficult to detect with traditional seismic processing; and
- larger installation equipment, sophisticated sea floor production handling equipment, expensive, state-of-the-art platforms and/or infrastructure investment.

Because we have exploration, exploitation and production operations in the deepwater Gulf of Mexico area, we are exposed to these risks. Furthermore, because of the generally higher expense of drilling wells in the deepwater Gulf of Mexico area, if such wells are economically unsuccessful, they may have a larger impact on our financial condition, results of operations and cash flows than wells that we drill in shallow water.

Properties we have acquired may not produce as projected, and we may not have fully identified liabilities associated with these properties or obtained adequate protection from sellers against liabilities.

In the past, we acquired producing properties from third parties, and these acquisitions required assessments of many factors, which are inherently inexact and may be inaccurate, including:

- the amount of recoverable reserves and the rates at which those reserves will be produced;

future oil and natural gas prices;

estimates of operating costs;

estimates of future development costs;

estimates of the costs and timing of plugging and abandonment activities; and

potential environmental and other liabilities.

Table of Contents

Our assessments may not have revealed all existing or potential problems, nor permitted us to become adequately familiar with the properties to evaluate fully their deficiencies and capabilities. In the course of our due diligence, we may not have inspected every well, platform or pipeline. Our inspections may not have identified structural and environmental problems, such as pipeline corrosion or groundwater contamination. We may not have obtained contractual indemnities from the seller for liabilities that it created. We may have assumed 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.

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 or 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.

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.

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

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

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

- a prohibition on the right of stockholders to call meetings and a limitation 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 Relating to the Oil and Natural Gas Industry

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.

The continuing crisis in the financial and credit markets, and volatility in oil and natural gas prices may affect our ability to obtain funding or to obtain funding on acceptable terms. These factors may hinder or prevent us from meeting our future capital needs and/or continuing to meet our obligations and conduct our business.

Global financial markets and economic conditions have recently been, and continue to be, disrupted and volatile. The debt and equity capital markets have become exceedingly distressed. These issues, along with significant asset write-offs in the financial services sector, the re-pricing of credit risk and the current weak economic conditions, have made, and will likely continue to make, it difficult to obtain debt or equity capital funding.

Due to these factors, there can be no assurance that funding will be available to us if needed, and to the extent required, on acceptable terms. If funding is not available as needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due, implement our exploratory and development plan, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities, or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues, results of operations, financial position and cash flows.

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. These markets will likely continue to be volatile in the future. 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;

Table of Contents

- the price and availability of liquefied natural gas imports;
- political conditions, including embargoes, in or effecting 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 effecting energy consumption; and
- the price and availability of alternative fuels.

In addition to decreasing our revenues and cash flows on a per unit basis, lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. Our insurance coverage may not be sufficient or may not be available to cover some of these losses and claims.

Losses and liabilities arising from uninsured and underinsured events could materially and adversely effect 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;
- mechanical difficulties;
- fires and explosions;
- personal injuries and death; and

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

Offshore operations are also subject to a variety of operating risks unique to the marine environment, such as capsizing, collisions and damage or loss from hurricanes, tropical storms or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses. We maintain insurance at levels that we believe are consistent with industry practices and our particular needs, but we are not fully insured against all risks. We may elect not to obtain insurance for certain risks or to limit levels of coverage if we believe that the cost of available insurance is excessive relative to the risks involved. In this regard, the cost of available coverage has increased significantly as a result of losses experienced by third-party insurers in the 2005 and 2008 hurricane seasons in the Gulf of Mexico, in particular those resulting from Hurricanes Katrina and Rita in 2005 and Gustav and Ike in 2008. We believe the cost of coverage will continue to increase and may become prohibitively expensive for smaller independent operators in the Gulf of Mexico. As a result, our coverage may be limited by longer waiting periods on business interruption insurance and higher deductibles on property damage and other types of insurance. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and it is not fully covered by insurance, it could adversely affect our financial condition, results of operations and cash flows and could reduce or eliminate the funds available for exploration, exploitation and acquisitions or result in loss of equipment and properties.

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.

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 based on prices and costs as of the date of the estimate. Actual future prices and costs may differ materially from those used in our reserve estimates.

If our estimates of the recoverable reserve volumes on a property are revised downward, or 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 depends 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.

If we are unable to replace the reserves that we have produced, our reserves and 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. Additionally, we have substantially cut our planned capital expenditures for 2009 in order to conserve cash resources, which will likely negatively impact our ability to replace existing reserves produced. 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.

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. Our business also requires substantial expenditures for routine maintenance. We may not have access to the capital required to maintain our production levels and reserves.

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,

Table of Contents

pipelines and processing facilities owned and operated by third parties and the availability of satisfactory oil and natural gas transportation arrangements. 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, our production could be limited or delayed and our revenues could be adversely affected.

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.

We are exposed to counterparty risk through our hedging activities using commodity derivative instruments and through other arrangements we enter into with financial and other institutions.

We have entered into transactions with counterparties such as commercial banks, investment banks, insurance companies, and other financial institutions. These transactions expose us to credit risk in the event of default of any of these counterparties. Continued deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us.

When we have oil and natural gas derivative contracts outstanding, we have exposure to these financial institutions related to such contracts, which may protect a portion of our cash flows when commodity prices decline. During periods of low oil and natural gas prices, we may have heightened counterparty risk associated with these derivative contracts because the value of our derivative positions may provide a significant amount of cash flow. If a hedging counterparty defaults on its obligations, we may not realize the benefit of some or all of our derivative instruments.

We also maintain insurance policies with insurance companies to protect us against certain risks inherent in our business. If an insurer defaults on its obligation to us, we may not be reimbursed for losses we have insured against. In addition, if any lender under our credit facility is unable to fund its commitment, our liquidity may be reduced by an amount up to the aggregate amount of such lender s commitment under our credit facility.

We are subject to extensive governmental laws and regulations, including environmental regulations, which 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.

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 Part I, Item 1, Business Environmental Regulations in this Annual Report.

If third party pipelines and other facilities interconnected to our natural gas pipelines and facilities become partially or fully unavailable to transport natural gas and NGLs, our revenues could be adversely affected.

We depend upon third party pipelines and other facilities that provide delivery options to and from our pipelines and facilities. Since we do not own or operate these pipelines or other facilities, their continuing operation is not within our control. If any of these third party pipelines and other facilities become partially or fully unavailable to transport natural gas and NGLs, 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 revenues could be adversely affected.

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 FERC regulation under the NGA, but FERC regulation still affects our non-FERC jurisdictional businesses and the markets for products derived from these businesses. The FERC has recently issued Order 704 requiring 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 to the FERC.

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 assure you 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 under the NGA. We believe that the natural gas pipelines in our gathering systems 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 services and federally unregulated gathering services is the subject of substantial, 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. 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, the courts, or Congress.

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 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 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 has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting. Additional rules and legislation pertaining to those and other matters 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.

Table of Contents

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 and Gulf Coast onshore 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 future revenues and growth may be diminished or restricted.

Recent adverse publicity about us, including our Chapter 11 filings, may harm our ability to compete in a highly competitive environment.

Recent adverse publicity concerning our financial condition may harm our ability to attract new customers and to maintain favorable relationships with existing customers, suppliers and partners. For example, it may be more challenging for us to engage in risk sharing transactions, and some of our suppliers may require cash payments rather than extending credit, which adversely affects our liquidity. We may also experience difficulty attracting and retaining key employees.

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 16, Commitments and Contingencies in the consolidated financial statements in Part II, Item 8 of this Annual Report.

Item 4. ***Submission of Matters to a Vote of Security Holders***

None.

Table of Contents

PART II

Item 5. ***Market for Registrant s Common Stock, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Our common stock is currently being quoted for public trading on the Pink Sheets quotations system, an over-the-counter market, under the symbol ERPLQ.PK. Prior to March 30, 2009, our common stock was listed on the 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 (through the First Quarter 2009) and the Pink Sheets quotations system (subsequent to First Quarter 2009).

	High ($)	Low ($)
2007		
First Quarter	$ 24.52	$ 16.97
Second Quarter	19.25	15.83
Third Quarter	18.04	12.04
Fourth Quarter	15.39	11.73
2008		
First Quarter	12.71	8.04
Second Quarter	16.50	9.24
Third Quarter	15.46	8.00
Fourth Quarter	8.91	1.19
2009		
First Quarter	2.34	0.08
Second Quarter	0.45	0.05
Third Quarter (through July 27, 2009)	0.38	0.27

On July 27, 2009, the last reported sale price of our common stock on the Pink Sheets quotations system was $0.35 per share.

As of July 27, 2009, there were approximately 153 holders of record of our common stock.

We have not paid any cash dividends in the past on our common stock and do not intend to pay cash dividends in the foreseeable future. We intend to retain earnings for the future operations and development of our business. 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, 2008, 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	2,054,021	$ 15.34	2,685,256
Equity compensation plans not approved by stockholders			
Total	2,054,021	$ 15.34	2,685,256

(1)

Comprised of 1,620,321 shares subject to issuance upon the exercise of options and 433,700 shares to be issued upon the lapsing of restrictions associated with restricted share units

(2) Restricted share units and performance shares do not have an exercise price; therefore, this only reflects the weighted-average option exercise price.

See Note 15 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 plans.

Table of Contents

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 by reference into such a filing.

The graph below matches our cumulative five-year total shareholder return on common stock with the cumulative total returns of the S&P 500 index and a customized peer group of seven independent oil and natural gas exploration and production companies. The peer group includes: ATP Oil & Gas Corp., Callon Petroleum Company, Mariner Energy, Inc., McMoRan Exploration Co., Stone Energy Corp., The Meridian Resource Corp. and W & T Offshore Inc. In 2008, we removed Bois d Arc Energy, Inc. from the peer group we used in our 2007 Annual Report to Stockholders because it was acquired by Stone Energy Corp. during 2008.

The graph tracks the performance of a $100 investment in our common stock, in the peer group, and the index (with the reinvestment of all dividends) from December 31, 2003 to December 31, 2008. This historic price performance is not necessarily indicative of future stock performance.

	12/03	12/04	12/05	12/06	12/07	12/08
Energy Partners, Ltd.	100.00	145.83	156.76	175.68	84.96	9.71
S&P 500	100.00	110.88	116.33	134.70	142.10	89.53
Peer Group	100.00	120.84	138.47	128.57	142.36	51.62

Table of Contents

Item 6. ***Selected Financial Data***

The following table shows selected consolidated 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.

	Years Ended December 31,				
	2008	2007 (1)	2006	2005	2004
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenue	$ 356,252	$ 454,649	$ 449,550	$ 402,947	$ 295,447
Income (loss) from operations (2)	(25,531)	(56,013)	(55,343)	132,027	86,068
Net income (loss)	(52,212)	(79,955)	(50,400)	73,095	46,416
Net income (loss) available to common stockholders (3)	(52,212)	(79,955)	(50,400)	72,151	43,017
Basic net income (loss) per common share	$ (1.63)	$ (2.32)	$ (1.32)	$ 1.94	$ 1.31
Diluted net income (loss) per common share	$ (1.63)	$ (2.32)	$ (1.32)	$ 1.79	$ 1.20
Cash flows provided by (used in):					
Operating activities	$ 184,610	$ 293,889	$ 272,074	$ 269,969	$ 165,074
Investing activities	(205,230)	(244,421)	(358,780)	(449,159)	(176,713)
Financing activities	13,747	(43,818)	83,131	92,442	784

	As of December 31,				
	2008	2007 (1)	2006	2005	2004
	(In thousands)				
Balance Sheet Data:					
Total assets	$ 766,766	$ 814,856	$ 1,003,845	$ 931,285	$ 647,678
Long-term debt, excluding current maturities (4)		484,501	317,000	235,000	150,109
Stockholders equity	57,119	101,970	372,269	394,593	315,049
Cash dividends per common share					

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

(2) The 2008, 2007, 2006 and 2005 income from operations includes business interruption insurance recoveries of $4.2 million, $9.1 million, $32.9 million and $20.6 million respectively from deferred production at our covered fields resulting from Hurricanes Gustav and Ike in 2008 and Katrina and Rita in 2005.

(3) Net income (loss) available to common stockholders is computed by subtracting preferred stock dividends and accretion of discount of $0.9 million and $3.4 million from net income (loss) for the years ended December 31, 2005 and 2004, respectively.

(4) At December 31, 2008, long-term debt classified as current totaled $497.5 million. At December 31, 2007 and 2006, none of our debt was classified as current. At December 31, 2005 and 2004, long-term debt classified as current was $0.1 million.

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

General

We were incorporated 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 shallow to moderate depth waters in the Gulf of Mexico focusing on the areas of offshore Louisiana as well as the deepwater Gulf of Mexico in depths less than 5,000 feet.

Table of Contents

Recent Events

Background to the Chapter 11 Cases. Prior to our filing the Chapter 11 Cases, a number of events and economic conditions which existed in 2008 negatively impacted our business and liquidity. These events included 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 have remained at 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:

MMS Order and Term Sheet. We received an order from the MMS dated March 23, 2009 (the MMS Order). The MMS is part of the United States Department of the Interior. The MMS Order demanded that we provide to the MMS bonds or other acceptable security in the aggregate amount of $34.7 million to secure plugging and abandonment liabilities associated with all of our properties on federal leases in the Gulf of Mexico, with the first installment payment of $1.2 million due no later than March 31, 2009, an additional installment payment of $1.2 million due no later than June 30, 2009 and the remaining $32.3 million due no later than July 31, 2009. The MMS Order also required us to immediately shut-in production from all of our wells and facilities located in South Pass Blocks 27 and 28 in the federal portion of our East Bay field, while properly maintaining these facilities and wells with essential personnel. We promptly completed the shut-in of our federal East Bay facilities before the end of March, 2009. The production from the wells and properties that we shut-in as a result of the MMS Order constituted less than 5% of our average daily production as of March 27, 2009. We also made two installment payments of approximately $1.2 million on March 30, 2009 and on April 29, 2009 in compliance with the MMS Order and the term sheet discussed below. We entered into a binding term sheet with the MMS on April 30, 2009 to establish terms for us to address our obligations under the MMS Order. Under the term sheet, we and the MMS have agreed to re-affirm the terms and conditions of the previously established trust account for the benefit of the MMS under the Decommissioning Trust Agreement dated December 23, 2008 among us, the MMS and JP Morgan Chase Bank, NA, and we had agreed to make monthly payments to the trust account in the amount of $1.2 million while the Chapter 11 Cases are pending and, on the effective date of the Plan to make a payment to the trust account equal to $21 million minus the aggregate amount of the monthly payments made into the trust account while the Chapter 11 Cases are pending (commencing with the payment made on April 29, 2009). The $1.2 million monthly payments to the trust account remain subject to approval by the Bankruptcy Court. All remaining amounts owed to the trust account to reach the full funding amount owed to the MMS of $36.1 million (after giving credit to all prior payments made by us) were payable in equal quarterly installments of approximately $1.2 million, commencing October 31, 2009, with quarterly payments continuing until full funding has occurred. On June 11, 2009, we received a letter from the MMS requesting an additional $10.95 million in financial assurance based on the actual costs for partial and completed well plugging and abandonment associated with our federal leases in the East Bay field. On June 24, 2009, we advised the MMS that we will provide the additional $10.95 million by increasing our quarterly payments identified in the term sheet such quarterly payments are presently contemplated to commence on October 31, 2009 which would increase the quarterly payments from approximately $1.2 million to approximately $1.8 million. The MMS agreed to vote in favor of the Plan to the extent its treatment is consistent with the terms set forth in the term sheet. In addition, the MMS has granted a consensual stay of the MMS Order that will remain in place while the Chapter 11 Cases are pending. This stay, however, does not lift the requirement that our Federal wells and facilities located in South Pass Blocks 27 and 28 remain shut-in. The term sheet with MMS contemplates that, on the effective date of the Plan, the MMS Order will be fully rescinded, and we will be allowed to resume production from these wells and facilities. However, the terms of the term sheet, as incorporated into the Plan, will only supersede the MMS Order if the Bankruptcy Court confirms the Plan.

[Table of Contents](#)

Reduction of Borrowing Base. In March 2009, we received a notice of redetermination from Bank of America, N.A., the Administrative Agent under the Credit Agreement, that our borrowing base under the Credit Agreement had been lowered from $150 million to $45 million, resulting in a borrowing base deficiency of $38 million. Following the receipt of this notice, we considered various alternatives provided for under the Credit Agreement to repay the borrowing base deficiency and presented to the Administrative Agent the proposal of an installment repayment plan. The Administrative Agent declined to approve our proposed repayment plan, and as a result, on March 24, 2009, we received a notice from the Administrative Agent requiring the lump-sum payment by us of $38 million to the bank lenders under the Credit Agreement (the Lenders) by April 3, 2009. On April 3, 2009, we obtained a consent from a majority of the outstanding commitments (the Required Lenders) under the Credit Agreement, extending the due date for the repayment of the borrowing base deficiency until April 14, 2009. On April 14, 2009, we and the Required Lenders entered into a letter agreement that further extended the due date for repayment of the borrowing base deficiency until May 1, 2009 and provided that the Lenders agree not to exercise any rights and remedies until May 1, 2009 with respect to all outstanding and certain anticipated defaults by us under the Credit Agreement in exchange for our compliance with specified conditions. On May 1, 2009, we filed the Chapter 11 Cases.

Default on Senior Unsecured Notes. We were required to make annual interest payments of approximately $45.0 million each year on the Senior Unsecured Notes, of which $17 million was due on April 15, 2009, and remains unpaid. Our failure to make these interest payments within 30 days of the due date was an event of default under the indenture governing the Senior Unsecured Notes and under the cross-default provision of the Credit Agreement.

Surety Obligations. As of July 1, 2009, we had outstanding $60.0 million in surety bonds with four different indemnity companies. Our agreements with these indemnity companies allow them to demand cash reserves or letters of credit to support our outstanding surety bonds. In December 2008 and the first quarter of 2009, we posted cash collateral to restricted accounts for the benefit of certain of these indemnity companies totaling $5.7 million in response to requests to provide reserves against our surety bonds with them. If we default on some or all of these surety bonds, the indemnity companies may cancel our surety bonds. The cancelation of some or all of our surety bonds may result in violations of other agreements or obligations. As a result, we could be forced to shut in our production or lose our ability to continue to perform our business operations.

Plan of Reorganization; Plan Support and Lock-Up Agreement. On April 30, 2009, we entered into a Plan Support and Lock-Up Agreement (the Plan Support Agreement) with the holders of more than 66 2/3% (the Consenting Holders) of the outstanding principal amount of our Senior Unsecured Notes. The parties to the Plan Support Agreement had agreed, following receipt of the Disclosure Statement, to vote in favor of and support a plan or reorganization that is consistent in all material respects with the term sheet attached to the Plan Support Agreement (Term Sheet).

The Plan Support Agreement may be terminated under certain circumstances by the Majority Consenting Holders, including if (1) we fail to file the Plan or the Disclosure Statement with the Bankruptcy Court on or prior to May 15, 2009; (2) the Bankruptcy Court does not approve the Disclosure Statement on or prior to June 30, 2009; (3) the Bankruptcy Court does not confirm the Plan on or prior to August 15, 2009; (4) we do not consummate the restructuring transactions provided for in the Plan on or prior to September 10, 2009, or under certain circumstances, a later date; (5) we or any of our officers or directors fail to take any action required by the Plan Support Agreement in order to comply with our fiduciary obligations under applicable law or otherwise; (6) we file or support a plan of reorganization that is different from the Plan or withdraw or revoke the Plan; (7) we materially breach any of our obligations or fail to satisfy in any material respect any of the terms or conditions under the Plan Support Agreement; (8) our aggregate liabilities as of the dates specified in the Term Sheet (excluding those liabilities that would be extinguished by the Plan or otherwise do not survive the consummation of the Plan) materially exceed the amounts we represented in the Term Sheet; (9) an examiner with expanded powers relating to our business or trustee is appointed in any of the Chapter 11 Cases, any of the Chapter 11 Cases are converted to a case under Chapter 7 of the Bankruptcy Code or any of the Chapter 11 Cases are dismissed by the Bankruptcy Court; or (10) any definitive documents executed by us in connection with the Chapter 11 Cases in order to implement the Plan are not consistent in all material respects with the terms set forth in the Term Sheet and otherwise are not reasonably satisfactory in all material respects to the Majority Consenting Holders. In any event, the Plan Support Agreement terminates on September 15, 2009.

Bankruptcy Proceedings, Plan of Reorganization, Exit Facility and Expected Emergence from Bankruptcy. 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, in the Bankruptcy Court. We continue to manage our properties and operate our business as debtors-in-possession under the jurisdiction of the Bankruptcy Court. On June 11, 2009, as part of the Chapter 11 Cases, we filed with the Bankruptcy Court the Plan and the Disclosure Statement, pursuant to which we solicited votes for the confirmation of the Plan. On July 31, 2009, we filed with the Bankruptcy Court our Second Amended Joint Plan of Reorganization, as modified as of July 31, 2009 (Plan). The Plan was formulated after extensive negotiations with committees representing holders of the Senior Unsecured Notes and holders of our common stock interests. The primary purpose of the Plan is to effectuate a restructuring of our capital structure to strengthen our balance sheet by reducing our overall indebtedness and improve cash flow.

On July 23, 2009, we announced that the Plan had received the affirmative vote of the holders of our Senior Unsecured Notes and our 8.75% Senior Notes due 2010 and we consequently proceeded to request confirmation of the Plan from the Bankruptcy Court. On August 3, 2009, after a confirmation hearing in which the Bankruptcy Court considered the Plan and all objections thereto, it entered into a confirmation order (Confirmation Order) and confirmed the Plan as of August 3, 2009. The effectiveness of the Plan and our emergence from bankruptcy is subject to several conditions, including the successful closing of the Exit Facility. We are currently in negotiations with lenders on structuring the Exit Facility. Fore more information on the conditions to the final effectiveness of the Plan see Item 1A Risk Factors.

The material terms of the Plan as confirmed by the Bankruptcy Court on August 3, 2009 include, among other things, that:

- each holder of the Senior Unsecured Notes and our 8.75% Senior Notes due 2010 would receive, in exchange for their total claim (including principal and interest), their pro rata share of 95% of the common stock to be issued pursuant to the Plan New EPL Common Stock in us upon our emergence from bankruptcy;

- each holder of our common stock interests would receive, in exchange for their total claim, their pro rata share of 5% of the New EPL Common Stock;

- upon the Effective Date, we shall have access to an exit working capital credit facility (Exit Facility) in form and substance acceptable to us and a majority in interest of the Consenting Holders (the Majority Consenting Holders); and

- we may adopt the 2009 Long Term Incentive Plan under which it may issue shares of restricted new EPL common stock and new EPL stock options to certain of its employees and certain members of management;

- following the effective date of the reorganization, the sole equity interests in us would consist of (1) New EPL Common Stock issued to the holders of our Senior Unsecured Notes, the 8.75% Senior Notes due 2010, and holders of our common stock interests, (2) restricted new EPL common stock issued to certain members of our management, if any, and (3) new EPL stock options to be issued to certain key employees pursuant to the 2009 Long Term Incentive Plan, if any, which would be exercisable for new EPL common stock. Collectively, the restricted new EPL common stock issued pursuant to subparagraph (2) and the shares reserved for the exercise of new EPL stock options pursuant to subparagraph (3) above would in no event exceed 3% of the new EPL common stock on a fully diluted basis.

The timing and ultimate outcome of the Chapter 11 proceedings remain uncertain. Issues and matters to be resolved prior to emergence from the proceedings include negotiation of the Exit Facility.

Consummation of the Plan is conditioned upon, among other things, the closing of the Exit Facility. There can be no assurance that any or all of the foregoing conditions will be met (or waived) or that the other conditions to consummation, if any, will be satisfied. Accordingly, there can be no assurance that the Plan will be consummated and the restructuring completed.

The above events and circumstances, together with the worldwide credit markets collapse in 2008 and the scarcity of available credit from most major commercial financial institutions, as well as the low trading price of our common stock, make it extremely difficult to find additional financing, either to refinance our Credit Agreement or our Senior Unsecured Notes or to provide additional liquidity during 2009.

Restructure of Prepetition Employee Arrangements. Prior to May 1, 2009, various incentive and retention plans and agreements existed for certain of our employees (collectively, the Arrangements) that provided for such employees to receive cash payments and/or settlement of equity compensation awards either upon specified future vesting dates or in connection with a termination of employment. The Plan Support Agreement contains certain provisions that provide that such Arrangements must be amended, renegotiated, and/or restructured prior to the effective date of a confirmed plan of reorganization.

As a result of the Plan Support Agreement, the Board of Directors amended the provisions of the Energy Partners, Ltd. Change of Control Severance Plan (the Severance Plan) in a manner such that the protected employment period initiated by our change of control under such plans, as well as the severance benefits potentially payable in connection with certain terminations of employment during that protected period, would not be triggered by the restructuring contemplated by the Plan Support Agreement.

We also established two programs, a non-insider employee retention program and a senior management employee program (collectively, the Retention Programs). In order for an office employee who participates in either of these programs to receive his or her retention payments, the participant has to waive and release any and all potential claims against the Company under the prepetition Arrangements.

Finally, the written change of control severance agreements (each a Severance Agreement) with two of our executives were terminated by the Company and each of such executives in exchange for the executives receiving an unsecured claim for the rejection damages.

The total cost of the Retention Programs and the termination of the two Severance Agreements is approximately $2 million of which approximately $0.5 million has been paid during the bankruptcy proceedings and approximately $1.5 million will be paid when we emerge from bankruptcy.

NYSE Delisting. In March 2009, the NYSE notified us that our common stock had been suspended from trading and was subsequently delisted for failure to maintain the required market capitalization minimum criteria. Our common stock is being quoted for public trading on the Pink Sheets quotations system, an over-the-counter market, under the symbol ERPLQ.PK. This significantly impairs our ability to raise additional equity financing.

Changes to Production Levels. Due to our current liquidity situation and lower commodity prices, we expect to significantly reduce capital expenditures during 2009. As a result, we do not expect to be able to maintain our current production levels and we expect our production to decline significantly during the second half of 2009 primarily due to natural reservoir declines combined with minimal investment in reserve replacement activities. At our current and anticipated production levels, combined with the current and expected lower sales prices, we do not expect to have sufficient cash flows to fully fund our operations and meet all of our financial obligations in 2009 as discussed above.

Table of Contents

Changes in the Board of Directors and Management. Commencing in the first half of fiscal 2009 and continuing through the date of this filing, we have experienced major changes in the management of our company. Our Board of Directors declined from eleven to five members during the first quarter of 2009. In addition, on March 1, 2009, Joseph T. Leary resigned as our Executive Vice President and Chief Financial Officer. On March 15, 2009, Richard A. Bachmann resigned as our Chairman and Chief Executive Officer and we engaged Alan D. Bell as our Chief Restructuring Officer. In July 2009, we announced the designation of Alan D. Bell as principal executive officer and Tiffany J. Thom as principal financial officer.

Overview and Outlook

Results of Operations

During the year ended December 31, 2008, we were successful in 16 of 17 drilling operations and 7 of 10 recompletion and workover operations, much of which was substantially completed before the fourth quarter of 2008. We significantly curtailed our drilling operations beginning in the fourth quarter of 2008 and expect to remain at significantly curtailed drilling activity levels during 2009 due to the factors impacting our liquidity addressed under Recent Events.

Our operating results for the year ended December 31, 2008 compared to the year ended December 31, 2007 reflect a decline in production from our existing core oil and natural gas properties due primarily to natural reservoir declines, and the impact of the hurricanes which shut in a significant amount of our production from September 2008 into early 2009, resulting in an average decline of approximately 18%, or 2,800 Boe per day reduction, from our pre-hurricane production. Our production level also declined due to the sales of producing properties in June 2007 and March 2008. The June 2007 sale of onshore producing properties (the June 2007 Property Sale) contributed an average of 2,742 Boe per day from January 1, 2007, through the June 12, 2007 sale date. These impacts were offset in part by successful drilling results in 2008.

Higher average oil and natural gas prices contributed favorably to our revenues for the year ended December 31, 2008 during which we realized a 44% increase in our average sales price per Boe (exclusive of derivative instruments) over the year ended December 31, 2007. The precipitous decline in oil and natural gas prices that began in the third quarter of 2008 is not fully reflected in our realizations for the full 2008 year because of the significant decline in our production as a result of the hurricanes which impacted production from September 2008 into early 2009.

For the year ended December 31, 2008, our revenues declined 22% as compared to the year ended December 31, 2007 due primarily to declines in production volumes. The declines in production volumes were due primarily to natural reservoir declines and the impact of hurricanes addressed above, partially offset by increases in the average sales price of our production during 2008.

In addition to the items addressed above, our net loss of $52.2 million for the year ended December 31, 2008 reflects:

- impairments of producing oil and natural gas properties of $39.3 million due primarily to the decline in estimated sales prices of oil and natural gas;

- impairments, due primarily to our cash flow constraints, of capitalized costs of $47.5 million related to two deepwater properties for which development activities are suspended pending the determination of proved reserves;

- impairments, due primarily to our cash flow constraints, of unevaluated property costs of $20.8 million related to leases expiring in 2009 and 2010;

- losses incurred on abandonment work of $21.7 million primarily related to abandonment work completed in 2008 and estimated cost of abandonment work planned for 2009;

- a decrease of $68.0 million in dry hole and exploratory costs as compared to 2007 primarily as a result of reduced exploratory drilling activities;

38

Table of Contents

a decrease in lease operating expense (Loe) as compared to 2007 resulting primarily from the June 2007 Property Sale and our efforts to reduce and control these costs in 2008, which decreases were partially offset by uninsured hurricane-related repair costs incurred in the latter part of 2008; and

a decrease in general and administrative expenses (G&A) as compared to 2007 resulting primarily from G&A during the year ended December 31, 2007 related to our review of strategic alternatives and the repurchase of 8,700,000 shares of our common stock at $23.00 per share, refinancing our bank credit facility and acquisition of substantially all of our existing $150 million 8.75% Senior Notes due 2010 (the Transactions).

Cash Flows

Our operating cash flows for the year ended December 31, 2008 were impacted by the hurricanes which caused nearly all of our production to be shut in at one time or another during the third and fourth quarters of 2008 and by lower oil and natural gas sales prices during the fourth quarter of 2008.

Our most significant current challenge is addressing our severe liquidity constraints by completing our Chapter 11 bankruptcy proceedings, securing exit financing and consummating the Plan. Our near term strategy includes the recapitalization of our balance sheet, targeted cost reduction activities, and significantly reduced drilling expenditures during 2009. The sales prices of our oil and natural gas will have a significant impact on our plans beyond 2009. If sales prices continue at the current low levels, our anticipated investment will not be adequate to maintain our current production levels and we expect our production to decline significantly during the second half of 2009 due primarily to natural reservoir declines. As further addressed under Financial Condition, Liquidity and Capital Resources, at our current and anticipated production levels, combined with the current and expected lower sales prices, we do not expect to have sufficient cash flows to fund our operations and meet our financial obligations in 2009.

Tropical Weather Impact

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. We maintained insurance coverage for property damage due to windstorms with a deductible of $10 million for each hurricane. For these occurrences, we also previously maintained business interruption insurance on a portion of our lost revenue on our South Timbalier 41, 42 and 46 properties, which represented 37% of our 2008 year to date daily production volumes prior to the hurricanes. Recovery of lost revenue from these properties began accruing in November 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 is recorded in other receivables at December 31, 2008. All of these amounts were collected in 2009. In order to mitigate the higher cost of insurance coverages in 2009, we negotiated higher deductibles and significantly lower aggregates for property damage due to windstorms. Further, we no longer maintain business interruption insurance.

Dispositions

In March 2008, we completed the sale of two Gulf of Mexico Shelf properties located in our Western offshore area (the March 2008 Property Sale) for $15.0 million after giving effect to preliminary closing adjustments. We recorded a gain on the sale of $7.1million.

We have included the results of operations of dispositions discussed above through their closing dates. We experienced substantial revenue and production fluctuations as a result of these dispositions and the tropical weather impacts discussed above. For these reasons the comparability of our historical results of operations with future periods may be materially impacted.

Table of Contents

Outlook

We continue to generate prospects and strive to maintain an extensive inventory of drillable prospects in-house and exposure to new opportunities through relationships with industry partners. Generally, we have attempted to fund any exploration and development expenditures with internally generated cash flows; however, from time to time during 2007 and more significantly in the fourth quarter of 2008, we used our bank credit facility to fund working capital needs as further discussed under the caption Financial Condition, Liquidity and Capital Resources.

While we expect drilling activities in 2009 to be significantly lower than in 2008, our long-term operating strategy is to increase our oil and natural gas reserves and production while focusing on reducing finding and development costs and operating costs to be competitive with our industry peers. During the year ended December 31, 2008, we were successful in 16 of 17 drilling operations and 7 of 10 recompletion/workover operations. Our 2008 drilling program was comprised predominately of lower risk, lower reserve potential opportunities, in order to stabilize production. Our near-term business strategy includes restructuring and recapitalization of our balance sheet, debt reduction, cost reduction activities and monitoring the reduction in equipment and service costs before committing to any future drilling programs. We have not established a capital expenditure budget for 2009 while assessing the results of these undertakings and the Chapter 11 Cases. We expect that any funding that may be approved for drilling in 2009 would be allocated primarily to lower risk development and exploitation opportunities.

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

We use the successful efforts method of accounting for our investment in oil and natural gas properties. Under this method, we capitalize lease acquisition costs, costs to drill and complete exploration wells in which proven reserves are discovered and costs to drill and complete development wells. Exploratory drilling costs are charged to expense if and when the well is determined not to have found reserves in commercial quantities. 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.

Unless specifically addressed, any discussion in this Part II, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations of our intent, plans or expectations or similar expressions of forward-looking statements may not consider the potential impact of the restructuring and recapitalization of our balance sheet in connection with the Chapter 11 Cases or any acquisition or merger of or by us or changes in plans and/or intentions resulting from changes in our management and/or Board of Directors that may result from the Chapter 11 Cases.

Table of Contents

Results of Operations

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

	Years Ended December 31, 2008	2007	2006
Net production (per day):			
Oil (Bbls)	5,608	8,769	8,238
Natural gas (Mcf)	45,070	92,167	106,042
Total (Boe)	13,120	24,130	25,912
Average sales prices, excluding impact of derivatives:			
Oil (per Bbl)	$ 97.42	$ 66.78	$ 59.78
Natural gas (per Mcf)	9.46	7.15	6.98
Total (per Boe)	74.15	51.59	47.57
Impact of derivatives (1):			
Oil (per Bbl)	$ 1.29	$ (5.11)	$
Natural gas (per Mcf)	(0.03)	0.09	(0.02)
Oil & natural gas revenues (in thousands):			
Oil	$ 199,948	$ 213,751	$ 179,752
Natural gas	156,074	240,589	269,434
Total	356,022	454,340	449,186
Average costs (per Boe):			
Loe	$ 13.65	$ 7.94	$ 6.22
Depreciation, depletion, amortization and accretion (DD&A)	22.43	19.82	21.43
Taxes, other than on earnings	2.34	1.12	1.44
G&A	9.10	7.01	12.70
Increase (decrease) in oil and natural gas revenue (net of hedging) due to:			
Change in prices of oil	$ 98,201	$ 21,053	
Change in production volumes of oil	(112,004)	12,946	
Total increase (decrease) in oil sales	(13,803)	33,999	
Change in prices of natural gas	77,739	7,351	
Change in production volumes of natural gas	(162,254)	(36,196)	
Total decrease in natural gas sales	(84,515)	(28,845)	
Total estimated net proved reserves:			
Oil (Mbbls)	21,637	28,123	29,914
Natural gas (Mmcf)	90,808	103,118	170,123
Total (Mboe)	36,771	45,309	58,268
Standardized measure of discounted future net cash flows (in thousands)	$ 416,171	$ 1,092,935	$ 893,474

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

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Revenues and Net Loss

	Years Ended December 31, 2008	2007	$ Change	% Change
		(in thousands)		
Oil and natural gas revenues	$ 356,022	$ 454,340	$ (98,318)	(22)%

Net loss	(52,212)	(79,955)	27,743	35%

Although our average oil and natural gas sales prices increased 44% during the year ended December 31, 2008, the increase was more than offset by 46% lower production primarily due to deferred production from shut-in pipelines during the third and fourth quarters of 2008 as a result of Hurricanes Gustav and Ike, which reduced our Boe per day by approximately 2,800 for the year ended December 31, 2008, natural reservoir declines, the June 2007 Property Sale (that contributed 2,742 Boe per day in 2007 through the June 12, 2007 sale date), and the March 2008 Property Sale (that contributed 300 Boe per day in 2008 through the March 27, 2008 sale date). We expect our revenues to decline significantly in 2009 due to significantly lower forecasted oil and natural gas sales prices as compared to 2008. We expect production in 2009 to decline compared to 2008 production as continued natural reservoir declines from our core producing properties and the impact of curtailed spending on reserve replacement in 2009 are expected to impact our production volumes. Our forecasts do not consider any significant production disruptions that may occur due to hurricanes or other catastrophic events, which could result in significant reductions in our production, revenues and cash flows from operations.

Our net loss for 2008 is due primarily to significant impairments, the impact of the 2008 hurricane season on our production, the decline in the fourth quarter of 2008 of oil and gas prices, and losses on abandonment work performed in 2008 and planned for 2009. These and other factors impacting our net loss for the period are addressed below. We expect to continue to incur net losses in 2009 due to declining production levels and projected low sales prices for our oil and natural gas. If actual experience does not improve significantly from the assumptions in our forecast, especially regarding sales prices for oil and natural gas, our net loss for 2009 could be significant and we may incur additional material impairments of our assets. Under Recent Events above is an expanded discussion of the impact of these challenges on our business.

In addition to the factors addressed above, the reduction in net loss for the year ended December 31, 2008 as compared to the year ended December 31, 2007 was also attributable to gains on derivative instruments in 2008 and lower Loe, exploration expenses, DD&A and G&A for the reasons summarized below.

Offsetting these items was a loss on abandonment of $21.7 million in 2008 resulting from the increase in abandonment activities in 2008 and estimated cost of abandonments scheduled for 2009. In addition, estimated recoveries from business interruption insurance were $4.2 million in 2008, a decline from the $9.1 million recorded in 2007. Additionally, for the year ended December 31, 2007, our total costs and expenses were reduced by a gain on insurance recoveries of $8.1 million, the impact of which was more than offset by the loss on early extinguishment of debt of $10.8 million.

Our 2008 tax benefit resulting from the loss for the period reflects a valuation allowance of $7.5 million against our deferred tax assets, resulting in an effective tax rate on our 2008 net loss of 24.6%. We have recorded significant net losses in the years ended December 31, 2008, 2007 and 2006. As a result, we are unable to conclude that it is more likely than not we will realize all of our deferred tax assets, which relate primarily to net operating losses, offset by deferred tax liabilities related to basis differences in our oil and natural gas properties. We recorded a valuation allowance for the amount by which deferred tax assets exceeded deferred tax liabilities as of December 31, 2008.

Table of Contents

Operating Expenses

Operating expenses consist of the following:

	Years Ended December 31, 2008	2007	$ Change	% Change
		(in thousands)		
Loe	$ 65,533	$ 69,919	$ (4,386)	(6)%
Exploration expenditures	30,199	98,209	(68,010)	(69)%
Impairments of properties	110,403	114,913	(4,510)	(4)%
DD&A	107,688	174,541	(66,853)	(38)%
G&A	43,706	61,724	(18,018)	(29)%
Taxes, other than on earnings	11,245	9,900	1,345	14%
Loss on abandonment	21,695	2,788	18,907	NM
Other	(4,438)	(12,248)	7,810	64%

NM=Not meaningful

The decrease in Loe for the year ended December 31, 2008 compared to the year ended December 31, 2007 is primarily due to a general decline from a reduction in producing properties as a result of the June 2007 Property Sale and the March 2008 Property Sale, fewer workovers in 2008, and ongoing efforts to reduce Loe costs during 2008. These reductions were partially offset by increases in Loe related to the impact of the 2008 hurricanes. On a per Boe basis, costs have increased due primarily to decreased production volumes and hurricane-related costs in 2008.

The decrease in exploration expenditures for the year ended December 31, 2008 compared to the year ended December 31, 2007 is primarily due to lower dry hole costs due to the increased success in our 2008 drilling activity which focused more on developmental drilling as compared to the higher level of exploratory drilling activity in 2007. Exploratory expenditures for the year ended December 31, 2008 is comprised of $21.8 million of dry hole costs primarily for two exploratory wells or portions thereof which were found to be not commercially productive and $8.4 million of seismic expenditures and delay rentals. The expense in the year ended December 31, 2007 is comprised of $87.1 million of dry hole costs for 11 exploratory wells or portions thereof which were found to be not commercially productive and $11.1 million of seismic expenditures and delay rentals. Our exploration expenditures and dry hole costs vary depending on the amount of our planned capital expenditures dedicated to exploration activities, the cost of services to drill wells and the level of success we achieve in exploratory drilling activities.

Our exploratory expenditures and dry hole costs will vary depending on the amount of our planned capital expenditures dedicated to exploration activities and the level of success we achieve in exploratory drilling activities. We significantly reduced our exploratory drilling expenditures in 2008. We expect our exploratory and dry hole costs to decline further in 2009, due to our planned significant reduction in exploratory spending.

Impairments of oil and natural gas properties were $110.4 million in 2008, of which $108.6 million was recorded during the fourth quarter. The impairment expense was primarily related to the deepwater prospects addressed below ($47.5 million), producing fields (primarily five) which were determined to have future net cash flows less than their carrying values due primarily to commodity price declines and reservoir performance resulting in the write down of these properties to their estimated fair values as of December 31, 2008 ($39.3 million) and the undeveloped properties addressed below ($20.8 million). We periodically assess our oil and natural gas assets for impairment based on factors described under the caption Discussion of Critical Accounting Estimates. In 2009, we have observed deterioration in the forward pricing curve for natural gas and for oil. We expect that this factor, among other factors, will result in impairment reviews in connection with the preparation of our quarterly financial statements in 2009, which may result in additional material impairments.

Table of Contents

Due to the factors impacting our liquidity addressed under the caption General above, our plans to mitigate those impacts, and uncertainties regarding our ability to obtain additional capital to proceed with our drilling and development plans in 2009 and beyond, we determined that we may not be able to fund our share of development costs related to two of our deepwater prospects, Mississippi Canyon 292 and Mississippi Canyon 204, each of which is suspended pending determination of proved reserves related primarily to the generation of a development plan including economic processing and handling agreements. As a result, we assessed these properties for impairment and, based on financial constraints, determined that the leases were impaired. We recorded a charge to earnings for the carrying value of these deepwater prospects of $47.5 million. We maintain our rights to participate in the development of these discoveries until we elect not to proceed with such development plans as may be proposed by the operator of the properties in accordance with the applicable joint operating agreements. If we elect not to proceed, we will lose our rights to participate in the deep zones in these leases. Additionally, we recorded an impairment charge of $5.0 million to write-off the carrying value of a south Louisiana shallow-water well for which drilling operations were suspended during 2008 because we relinquished our interest in the lease.

Applying similar criteria to our portfolio of undeveloped leases, we determined that we may not be able to fund drilling activities required to maintain our unevaluated leases that expire in 2009 and 2010. As a result, we assessed these properties for impairment, and based on financial constraints, determined that the leases are impaired.

Our 2007 impairment expense totaled $114.9 million related to 17 fields. Eight fields with a net book value of $79.4 million experienced mechanical difficulties or facility requirements and it was determined that significant capital would be needed to extend their economic lives and, with our decreased capital budget, we decided that our capital would be better deployed to other projects. Another six fields with a net book value of $15.9 million underperformed and depleted earlier than anticipated. The remaining three fields had estimated future net cash flows less than their carrying values due to performance issues and reserve revisions, resulting in impairment expense of $19.6 million to write down the assets to their estimated fair values at December 31, 2007.

The decrease in depreciation, depletion and amortization (DD&A) was primarily due to decreased production volumes from deferred production caused by Hurricanes Gustav and Ike, natural reservoir declines, the sale of substantially all of our onshore South Louisiana assets in June 2007 and the sale of two of our Western Gulf of Mexico properties in March 2008. We anticipate that our DD&A in 2009 will increase in total and on a per Boe basis. While the material impairments recorded in 2008 would typically result in a decline in DD&A in 2009, a significant portion of the impairments recorded in 2008 were related to non-producing properties (undeveloped properties and properties for which development activities were suspended) for which no DD&A was recorded in 2008.

G&A decreased primarily due to $9.4 million of financial and legal advisory fees that were incurred during the prior year ended December 31, 2007 related to the exploration of strategic alternatives and the Transactions (see Financial Condition, Liquidity and Capital Resources Capital Transactions below). Included in G&A is cash and non-cash stock based compensation of $6.5 million and $9.4 million in the years ended December 31, 2008 and 2007, respectively. Our G&A includes $13.0 million and $12.7 million related to insurance coverage in 2008 and 2007, respectively, of which $11.0 million and $10.0 million in 2008 and 2007, respectively, is related to insurance for our oil and natural gas producing properties, including business interruption and property damage insurance coverages.

Taxes, other than on earnings increased for the year ended December 31, 2008 compared to the year ended December 31, 2007, due to higher average sales prices for oil (which is taxed based on value) offset by reduced production of oil and natural gas due to the sale of onshore properties in 2007. These taxes may fluctuate from period to period depending on our production volumes from non-federal leases and commodity prices received.

Table of Contents

During 2008, we began to plug and abandon a significant number of wellbores and began decommissioning associated with platforms, structures, pipelines and facilities on leases in the Gulf of Mexico that are no longer producing and were required, in most instances, to be performed during that period under MMS requirements. The level of abandonment activity we performed in 2008 was significantly higher than in any past period and was performed at a high pricing point in the market for such services with equipment, in some cases, that exceeded the capability of less costly equipment capable of performing such operations. Further, because we performed this work at a suboptimal time of the year, we were significantly impacted by weather delays. We incurred costs significantly in excess of our recorded asset retirement obligation (ARO) for this work. As a result of this experience, and our cost experience on other 2008 abandonment activities, as well as our efforts to estimate our planned work for 2009, we revised our estimated abandonment costs where appropriate to reflect recent experience in determining the estimated fair value of our abandonment obligations. The total impact of our revisions to ARO resulted in a loss on abandonment of $21.7 million in 2008. Revisions to ARO that did not result in an impact to 2008 earnings were recorded as additions to our oil and natural gas properties account and are amortized to DD&A over remaining units-of-production.

Other operating expenses consist primarily of net gains on asset sales in 2008 and 2007 and gains from insurance recoveries in 2007.

Other Income and Expense

	Years Ended December 31, 2008	2007	$ Change	% Change
		(in thousands)		
Interest expense	$ (46,533)	$ (46,213)	$ (320)	(1)%
Loss on early extinguishment of debt		(10,838)	10,838	NM
Gain (loss) on derivative instruments	2,053	(13,083)	15,136	116%

NM=Not meaningful

The increase in interest expense for the year ended December 31, 2008 compared to the year ended December 31, 2007 was primarily attributable to an increase in average borrowings due to the issuance of $450 million in aggregate principal amount of Senior Unsecured Notes in April 2007 combined with borrowings on our bank credit facility, offset by the repurchase of $145.5 million in aggregate principal amount of the $150 million 8.75% Senior Notes due 2010 completed in May 2007.

A loss on early extinguishment of debt for the refinancing of the bank credit facility and the repurchase of the 8.75% Senior Notes due 2010 of approximately $10.8 million was recorded during the year ended December 31, 2007. This loss includes the write-off of previously capitalized unamortized deferred financing costs related to the previous bank credit facility and the $150 million 8.75% Senior Notes due 2010 as well as the consent fees relating to the tender offer for the $150 million 8.75% Senior Notes due 2010. Due to the reduction in our borrowing base in the first quarter of 2009, we expect to record a reduction in the deferred financing costs related to the bank credit facility of approximately $1 million in 2009, which will increase interest expense by the same amount.

For the year ended December 31, 2008, gain (loss) on derivative instruments includes an unrealized gain of $19.1 million due to the change in fair market value of derivative instruments to be settled in the future and a loss of $17.0 million on contracts settled during 2008 for a total net gain of $2.1 million. For the year ended December 31, 2007, gain (loss) on derivative instruments includes an unrealized loss of $13.7 million due to the change in fair market value of derivative instruments to be settled in the future and a gain of $0.6 million on contracts settled during 2007 for a total net loss of $13.1 million.

Table of Contents

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Revenues and Net Loss

	Years Ended December 31, 2007	2006	$ Change	% Change
	(in thousands)			
Oil and natural gas revenues	$ 454,340	$ 449,186	$ 5,154	1%
Net loss	(79,955)	(50,400)	(29,555)	(59)%

Our oil and natural gas revenues increased during the year ended December 31, 2007 compared to the year ended December 31, 2006. Although production decreased primarily due to the sale of substantially all of our onshore South Louisiana assets in June 2007 (approximately 3,175 Boe per day) combined with natural reservoir declines, we had a slight increase in oil production, which had a higher price than natural gas on an equivalent basis, during the year as well as an increase in both oil and natural gas prices as illustrated in the above tables.

Our increased loss for the year ended December 31, 2007 compared to the year ended December 31, 2006 was largely due to higher lease operating expenses, exploration expenditures including dry hole costs and impairments, loss on derivative instruments and financing costs discussed below. This increased net loss was partially offset by lower G&A in 2007 as compared to 2006, which included expenses of $54.5 million relating to the terminated Merger Agreement with Stone (as discussed and defined below), and the $6.5 million gain recorded in 2007 on the sale of substantially all of our onshore South Louisiana assets in 2007.

As a result of Hurricanes Katrina and Rita and three other hurricanes that traversed the Gulf of Mexico and adjacent land areas in 2005, nearly all of our production was shut in at one time or another during the third quarter of 2005 and into 2006. We maintained business interruption insurance during this period on our significant properties, including our East Bay properties on which recovery of lost revenue continued to accrue through October 2006. We recognized a total of $62.6 million for business interruption recoveries of which $32.9 million and $20.6 million were recorded in 2006 and fourth quarter of 2005, respectively. An additional $9.1 million of business interruption recoveries was recorded in the first quarter of 2007 upon final settlement of the Hurricane Katrina claim. All insurance receivables related to these hurricanes have been collected.

On June 22, 2006, we entered into a merger agreement (Merger Agreement) with Stone Energy Corporation (Stone). Prior to entering into the Merger Agreement, Stone terminated its then existing merger agreement with Plains Exploration Company (Plains). Under the terms of the terminated merger agreement between Stone and Plains, Plains was entitled to a termination fee of $43.5 million, which was advanced by us to Plains. This proposed merger was not consummated and the termination fee was recorded in G&A expenses in 2006 (see additional discussion under Operating Expenses below).

Operating Expenses

	Years Ended December 31, 2007	2006	$ Change	% Change
	(in thousands)			
Loe	$ 69,919	$ 58,808	$ 11,111	19%
Exploration expenditures	98,209	51,745	46,464	90%
Impairments of properties	114,913	84,680	30,233	36%
DD&A	174,541	202,734	(28,193)	(14)%
G&A	61,724	120,113	(58,389)	(49)%
Taxes other than on earnings	9,900	13,632	(3,732)	(27)%

46

Table of Contents

The increase in Loe for the year ended December 31, 2007 compared to the year ended December 31, 2006 is primarily a result of new wells in new fields ($1.4 million), workover, maintenance and pipeline repair costs and equipment mobilization costs ($7.0 million), and various increases in fields with increased production. These increases were partially offset by the sale of our onshore South Louisiana assets ($1.5 million decrease). Contributing to the increase on a per Boe basis were production declines from existing fields with fixed costs and the workover, maintenance and pipeline repair costs discussed.

The increase in exploration expenditures for the year ended December 31, 2007 compared to the year ended December 31, 2006 is primarily due to our lower success rate and the higher average cost for each exploratory well. The expense in 2007 is comprised of $87.1 million of costs for 11 exploratory wells or portions thereof which were found to be not commercially productive and $11.1 million of seismic expenditures and delay rentals. The expense in 2006 is comprised of $37.5 million of costs for six exploratory wells or portions thereof which were found to be not commercially productive and $14.2 million of seismic expenditures and delay rentals.

During 2007, we recorded impairments of properties in 17 fields. Eight fields with a net book value of $79.4 million experienced mechanical difficulties or facility requirements and we determined that significant capital would be needed to extend their economic lives. With our decreased capital budget in 2008, we decided that this capital would be better deployed to projects with more potential. Another six fields with a net book value of $15.9 million underperformed and fully depleted earlier than anticipated. The remaining three fields were determined to have future projected cash flows of less than their net book values due to performance issues and reserve revisions; therefore, we recorded an impairment charge of $19.6 million to write down the assets to their fair values during 2007. During 2006, we recorded impairments of properties in eight fields, four of which were onshore assets acquired during an acquisition in January of 2005. Three of these onshore fields along with three offshore fields experienced downward revisions of recoverable reserves at December 31, 2006. These revisions along with decreased oil and natural gas prices resulted in impairments of $52.1 million on these assets. We elected to release the lease on the remaining onshore field. One other offshore field experienced mechanical difficulties. We determined that significant capital would be needed to extend its economic life and that this capital would be better deployed to projects with more potential. We wrote off the net book value of these assets of $27.0 million during 2006.

The decrease in DD&A for the year ended December 31, 2007 compared to the year ended December 31, 2006 was primarily due to the sale of substantially all of our onshore South Louisiana assets in June 2007 ($55.1 million) partially offset by higher DD&A on our Greater Bay Marchand area due to increased production and capital expenditures in 2007 ($31.8 million).

The overall decrease in G&A for the year ended December 31, 2007 compared to the year ended December 31, 2006 was primarily attributable to expenses of $54.5 million incurred during 2006 related to the terminated Merger Agreement with Stone as well as legal and financial advisory costs of $15.0 million in 2006 associated with an unsolicited offer from Woodside Petroleum, Ltd. (Woodside) and the ensuing strategic alternatives process. In 2007, we expensed a total of approximately $9.4 million in financial and legal advisory fees related to the exploration of strategic alternatives and the unsolicited Woodside offer. In addition, G&A included stock-based compensation of $9.4 million and $10.7 million in the years ended December 31, 2007 and 2006, respectively.

The decrease in taxes, other than on earnings for the year ended December 31, 2007 compared to the year ended December 31, 2006 was due to the sale of substantially all of our onshore South Louisiana assets in June 2007 partially offset by a sharp increase in oil prices during the year.

Other Income and Expense

	Years Ended December 31, 2007	2006	$ Change	% Change
	(in thousands)			
Interest expense	$ (46,213)	$ (24,570)	$ (21,643)	(88)%
Loss on early extinguishment of debt	(10,838)		(10,838)	NM
Unrealized loss on derivative instruments	(13,083)		(13,083)	NM

NM=Not meaningful

The increase in interest expense for the year ended December 31, 2007 compared to the year ended December 31, 2006 is primarily attributable to a net increase in average borrowings due to the issuance of the Senior Unsecured Notes in April 2007 offset by the repurchase of $145.5 million in aggregate principal amount of the 8.75% Senior Notes due 2010 completed in May 2007, combined with increased borrowings on our bank credit facility. Also included in the expense is a $2.3 million commitment fee paid in April 2007 for the availability of a bridge loan, which was not utilized, to facilitate the refinancing.

A loss on early extinguishment of debt for the refinancing of the bank credit facility and the repurchase of the 8.75% Senior Notes due 2010 was recorded during the year ended December 31, 2007. This loss includes the write-off of unamortized deferred financing costs related to the bank credit facility and the 8.75% Senior Notes due 2010 as well as the consent fees relating to the tender for the 8.75% Senior Notes due 2010.

For the year ended December 31, 2007, unrealized loss on derivative instruments includes an unrealized loss of $13.7 million due to the change in fair market value of contracts to be settled in the future and a gain of $0.6 million in contracts settled during the year.

Financial Condition, Liquidity and Capital Resources

	Years Ended December 31, 2008	2007	$ Change	% Change
	(in thousands)			
Net cash provided by operating activities	$ 184,610	$ 293,889	$ (109,279)	(37)%
Net cash used in investing activities	(205,230)	(244,421)	39,191	16%
Net cash provided by (used in) financing activities	13,747	(43,818)	57,565	131%

Analysis of 2008 Cash Flows

The decrease in our 2008 cash flows from operations primarily reflects the impact of the hurricanes on our production during 2008, offset by higher average sales prices for our production. Our accounts receivable declined by 38% from 2007 to 2008, reflecting the decline in production and the precipitous decline in oil and natural gas sales prices as of December 31, 2008. Though we incurred $24.6 million in abandonment activities in 2008, our asset retirement obligation increased due primarily to revisions of abandonment estimates in 2008. Despite a significant decline in drilling activity in the fourth quarter of 2008, our accounts payable and accrued expenses have not declined meaningfully as compared to December 31, 2007, in part due to our efforts to increase the time period between when costs are incurred and when we make cash payments to vendors.

Net cash used in investing activities declined in 2008 as a result of curtailed capital expenditures in response to declining oil and natural gas sales prices, contraction in the credit markets and reduced liquidity resulting from the MMS request for supplemental bonding or other acceptable security. In 2008, net cash used in investing activities consisted primarily of oil and natural gas exploration and development expenditures and lease purchases offset by proceeds of $15.6 million primarily from the March 2008 property sale. Dry hole costs resulting from exploratory expenditures are included in investing activities unless the expenditures do not result in the acquisition of an asset, such as geological and geophysical costs, costs of carrying and retaining undeveloped properties, and dry hole costs. Net cash used in investing activities in 2007 consisted primarily of oil and natural gas exploration and development expenditures offset by proceeds from property sales of $68.6 million as well as proceeds from insurance recoveries of $19.6 million.

Net cash provided by financing activities in 2008 reflects net proceeds from long term debt as a result of increased utilization of our 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 the fourth quarter of 2008. Net cash used in financing activities in 2007 reflects the purchase of $200.9 million of treasury stock, refinancing of our revolving credit facility and acquisition of substantially all of the 8.75% Senior Notes due 2010 with the proceeds from the issuance of the Senior Unsecured Notes.

We have not paid any cash dividends in the past on our common stock and do not intend to pay cash dividends in the foreseeable future. We intend to retain earnings for the future operations and development of our business. 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.

Liquidity and Capital Resources

The content under Recent Events above addresses important factors affecting our financial condition, liquidity and capital resources including the Chapter 11 Cases, impact of the significant reduction in our borrowing base in 2009, debt compliance violations, defaults on our bank credit facility and Senior Unsecured Notes, and surety obligations and anticipated decline in production and cash flows.

At December 31, 2008, our unrestricted cash on hand was $2.0 million and we had $43 million in borrowings on our bank credit facility.

During the quarter ended December 31, 2008, and continuing into the first quarter of 2009, we used our bank credit facility primarily to bridge a decline in our operating cash flows resulting from damage caused by Hurricanes Gustav and Ike to third party sales pipelines, which has prevented us from bringing a significant part of our production to market during the third and fourth quarters of 2008 and the decline in oil and natural gas prices during that time. We also incurred $24.6 million in abandonment activities in 2008. Despite a significant decline in drilling activity in the fourth quarter of 2008, our accounts payable and accrued expenses have not declined meaningfully as compared to December 31, 2007, in part due to our efforts to increase the time period between when costs are incurred and when we make cash payments to vendors.

We maintain deposits in a trust for future abandonment costs at our East Bay property. The trust was originally funded with $15 million and, with accumulated interest, has 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 property. We have made draws to date of $3.4 million, all of which were made in 2009. Amounts on deposit in the trust account are reflected in other assets.

We expect our cash flows from operations to decline in 2009 as a result of lower anticipated sales prices for oil and natural gas and, due to our plans to reduce capital expenditures and the impact of those reductions on reserve replacement and production enhancement. We expect our cash used in investing activities will decline significantly as a result of our plans to reduce capital expenditures in 2009. Prior to receiving the reduced borrowing base redetermination on our bank credit facility, we had forecasted to use our bank credit facility to continue funding projected working capital shortfalls during 2009. As a result of the decline in our borrowing capacity, our strategic alternatives are significantly limited and will require that we implement and execute the Plan in order to continue to meet our obligations.

Our exploration and development expenditures for 2008 totaled $205.1 million. We expect that our exploration and development activities in 2009 will be significantly lower than in prior years. For 2009, we expect exploration and development expenditures to total less than $10 million, which we expect would be directed primarily toward selective efforts to maintain existing production levels. Our planned expenditures for 2009 do not include any acquisitions or deepwater activities. We expect that any funding that may be approved for drilling in 2009 would be allocated primarily to lower risk development and exploitation opportunities. We also expect to incur abandonment costs of approximately $18.1 million in 2009 on several of our properties in accordance with the applicable regulatory requirements. We expect the abandonment work related to our East Bay field will be funded in part by expected draws of approximately $3.4 million in 2009 from restricted escrow funds previously set aside for this work.

The level of our planned capital expenditures is based on many factors, but the primary items driving capital expenditure decisions currently include obligations for our cash flows related to principal and interest on our currently outstanding debt and, if the Plan is approved as proposed, our potential future debt, other existing obligations including reducing our working capital deficit, estimates for oil and natural gas sales prices, general industry conditions including the level of pricing for equipment and services, and the anticipated level of participation by other working interest owners and the costs of drilling rigs and other oilfield goods and services. We believe that potential industry partners, including those with significantly more resources than us, may choose to defer significant projects and capital expenditures in an effort to preserve cash and strengthen their balance sheets. As a result, we believe the likelihood that we will be able to partner with other working interest owners to explore and develop new opportunities in the near term is diminished as compared to our past expectations.

Based on our planned capital expenditures, we expect that we will not be able to replace reserves at a rate that will allow us to maintain production levels. If actual experience does not improve significantly from the assumptions in our forecast, especially regarding sales prices for oil and natural gas, and our capital expenditures continue at the low levels projected for 2009, we expect that our production will decline significantly in the second half of 2009. Our forecasts do not consider any significant production disruptions that may occur due to hurricanes or other catastrophic events. At our current and anticipated production levels, combined with current sales prices, we do not expect to have sufficient cash flows to fully fund our operations and meet all of our financial obligations in 2009.

We have experienced and expect to again experience substantial working capital deficits. We had a working capital deficit at December 31, 2008 of $575.4 million, including the impact of our total debt of $497.5 million which is classified as a current liability at December 31, 2008. Excluding the impact of our debt, our working capital deficit was $77.9 million at December 31, 2008. 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. In 2008, our working capital deficit continued as a result of the impacts to our production and cash flows and changes in the timing of our payments to vendors discussed below. We forecast that our liquidity requirements will continue to increase during 2009, due primarily to expected production declines and forecasted lower sales prices for oil and natural gas. Our accounts payable at December 31, 2008 compared to December 31, 2007 reflects an increase in the time period from when costs are incurred and cash payments are made to vendors for those services.

The MMS recently communicated that it will 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 MMS granted approval to operators to maintain these structures in order to conduct other future activities; however, we expect that this practice will be more limited in the future. The MMS has stated that these measures are in response to the experiences in recent hurricane seasons in which idle structures were damaged or destroyed. We recently responded to an MMS 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. As a result, we reviewed a plan with the MMS to perform wellbore plugging and abandonment and decommissioning work on certain facilities and structures in our East Bay field during 2009, 2010 and 2011.

The MMS 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. Under limited circumstances, the MMS could require us to suspend or terminate our operations on a federal lease. 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.

Debt Compliance

Currently, we are in default on our Credit Facility, Senior Unsecured Notes and our 8.75% Senior Notes due 2010.

In November 2008, our credit facility was redetermined with a borrowing base of $150 million. At December 31, 2008, we had a borrowing base of $150 million and $43 million outstanding under the credit facility. In March 2009, our borrowing base was redetermined at $45 million, at which time we had $83 million outstanding resulting in a deficiency of $38 million. The significant effects of this 2009 redetermination are addressed under Recent Events above. We are not able to borrow on the credit facility. The credit facility is secured by substantially all of our assets. The credit facility permitted both prime rate borrowings and London InterBank Offered Rate (LIBOR) borrowings plus a floating spread. The spread floats up or down based on our utilization of the credit facility. While we were not in default under the Credit Agreement as of December 31, 2008, we subsequently failed to timely satisfy a number of 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, among other covenants.

In 2008, under the terms of our bank credit facility, the interest rate spread ranged from 1.00% to 2.5% above LIBOR and 0% to 0.50% above prime. In addition we paid an annual fee on the unused portion of the bank credit facility ranging between 0.25% to 0.50% based on utilization. The bank credit facility contains customary events of default and various financial covenants, which required us to: (1) maintain a minimum current ratio, as defined by our bank credit facility, of 1.0x, (2) maintain a minimum Consolidated EBITDAX to interest ratio, as defined by our bank credit facility, of 2.5x, and (3) maintain a ratio of long-term debt to Consolidated EBITDAX below 3.0. On March 11, 2009, we were advised of a borrowing base redetermination in the amount of $45 million, which resulted in a borrowing base deficiency of $38 million. Our failure to cure this borrowing base deficiency by May 1, 2009 constituted an event of default under our bank credit facility. Subsequent to such date, we have been paying interest at the foregoing rates plus 2% per annum (the default rate). See Recent Events in Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations for more information on the borrowing base redetermination.

The current ratio, as defined by our bank credit facility, includes (among other terms) in current assets our unused availability on the bank credit facility for purposes of satisfying the minimum current ratio covenant. As a result, for purposes of complying with the minimum current ratio covenant at each quarterly compliance reporting date, our working capital deficit, as adjusted by the terms of the bank credit facility, reduces the amount available for borrowings under the bank credit facility.

Table of Contents

Capital Transactions

In April 2007, we repurchased 8,700,000 shares of our common stock at $23.00 per share, refinanced our revolving credit facility and acquired substantially all of our existing $150 million aggregate principal amount 8.75% Senior Notes due 2010 pursuant to the Transactions. We sold selected properties following the completion of the Transactions to reduce debt under our new bank credit facility. In order to fund the Transactions, we undertook a private offering of the Senior Unsecured Notes and entered into a new bank credit facility. In conjunction with the termination of a previous plan of merger with Stone, we paid $8.0 million to Stone, which was included in general and administrative expenses in the fourth quarter of 2006. In addition, the $43.5 million termination fee that was advanced to Plains in June 2006 on behalf of Stone was expensed in 2006 along with other merger and strategic alternatives related costs of $15.0 million. We incurred $9.4 million of financial and legal advisory fees during 2007 related to these activities. In November 2007 we consummated an exchange offer pursuant to which we exchanged registered senior unsecured notes having substantially identical terms as the privately placed Senior Unsecured Notes.

On May 4, 2007, we completed a cash tender offer for our 8.75% Senior Notes due 2010. Approximately $145.5 million of the 8.75% Senior Notes due 2010 were repurchased and substantially all of their covenants have been removed.

On June 12, 2007, we sold substantially all of our onshore South Louisiana producing assets for $72.0 million in cash. After giving effect to closing adjustments, the net cash proceeds received totaled approximately $68.6 million. We used the proceeds to pay down a portion of our revolving credit facility.

During 2007, we also acquired 59,500 shares of our common stock for $0.8 million, an average price of $13.71 per share, under our since expired stock repurchase program.

Disclosures about Contractual Obligations and Commercial Commitments

The following table aggregates the contractual commitments and commercial obligations that affect our financial condition and liquidity position as of December 31, 2008. The table does not reflect any potential changes to our contractual obligations and commercial commitments that may result from the Chapter 11 bankruptcy proceedings and the activities contemplated in the Plan. For example, the Plan contemplates a debt-for-equity swap that would eliminate $454.5 million of our debt which is reflected in the table below. The table below does not include contractual interest payment obligations that would have been required for the original term of our Senior Unsecured Notes and the 8.75% Senior Notes due 2010 because those obligations are classified as current obligations in the table.

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	Thereafter
			(In thousands)		
Debt	$ 497,501	$ 497,501	$	$	$
Operating leases	12,745	1,855	3,372	3,419	4,099
Unconditional purchase obligations	334	334			
Asset retirement obligations	196,924	18,181	27,009	23,454	128,280
Other long-term liabilities	548		548		
Total contractual obligations	$ 708,052	$ 517,871	$ 30,929	$ 26,873	$ 132,379

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

Table of Contents

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 2 Summary of Significant Accounting Policies and Note 12 Derivative Transactions in Part II, Item 8 of this Annual Report describe our commodity price risks and the instruments we use to manage them.

We may, in the future, enter into derivative instruments to reduce our exposure to fluctuations in the market prices of oil and natural gas. Hedging transactions could 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 the bank 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 and the full cost method. We believe 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, we recognize exploration costs and dry hole costs as an expense on the income statement when incurred. We capitalize the costs of successful exploratory wells in oil and natural gas properties. 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. 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 is 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 Statement of Financial Accounting Standards Board (SFAS) No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets (SFAS No. 144) which measures impairments based on the estimated fair value of oil and natural gas properties on a field-by-field basis. SFAS No. 144 requires that 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.

Table of Contents

We use the successful-efforts method of accounting for our oil and natural gas properties because we believe that it more accurately reports asset values of our oil and natural gas properties in the balance sheet. We believe that recording dry hole costs in the period in which they are incurred results in reported earnings that more accurately reflect the results of our drilling operations during the period.

We believe that companies with active exploratory drilling programs typically incur dry hole costs. During the last three years we have drilled 49 exploratory wells, of which 18 were classified as dry holes. Dry hole costs charged to expense during the last three years totaled $146.4 million, or 81% of total exploratory drilling costs during the same period of $180.2 million. 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, i.e., prices and costs as of the date the estimate is made.

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

At December 31, 2008, proved oil and natural gas reserves were 36.8 million barrels of oil-equivalent (Mmboe). Approximately 68% of our proved reserves is classified as either proved undeveloped or 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 18% of total proved reserves are categorized as proved undeveloped reserves. As of December 31, 2008, none of our proved undeveloped reserves are under development nor expected to become proved developed within one year.

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 SEC guidelines, we use prices and costs determined on the date of the estimate 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.

At December 31, 2008, the computation of the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves was based on period-end prices of $6.05 per Mcf for natural gas and $44.77 per barrel for crude after adjusting the West Texas Intermediate posted price per barrel and the Gulf Coast spot market price per Mmbtu for energy content, quality, transportation fees, and regional price differentials for each property. We estimated the costs based on costs incurred during 2008 for individual properties. Where a particular property did not have production during the year, we applied 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 2008 we had negative revisions of 5.5 Mmboe, representing 12% of our total proved reserves of 45.3 Mmboe as of December 31, 2007. In 2007 we had downward revisions of 5.3 Mmboe, representing 9% of our total proved reserves as of December 31, 2006. In 2006 our reserve revisions were insignificant. The negative revisions in 2008 resulted from a combination of price decreases in both oil and natural gas (3.5 Mmboe) and underperformance (2.0 Mmboe). The negative revisions in 2007 were a combination of performance revisions and the removal of 4.1 Mmboe of proved reserves on impaired fields due primarily to the decision not to perform well work to restore the related wells to productive status. 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.

We base our assessment of possible impairment of proved oil and natural gas properties using 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 impairment expense of $110.4 million, $114.9 million and $84.7 million in the years ending December 31, 2008, 2007 and 2006.

We allocate the capitalized cost of unevaluated properties (those with no corresponding proved reserves) to earnings generally over the average term of each pool of unevaluated properties. We estimate the amount of capitalized costs of unevaluated properties which will prove unproductive by amortizing the balance of each pool of unproved property costs (adjusted by our expected success rate for future development) over an estimated average lease term. If we find oil and natural gas reserves sufficient to justify development of the property, we transfer the capitalized cost of an unproved property to proved properties where DD&A will be recorded on the units-of-production basis described above. If our efforts do not result in proved oil and natural gas reserves, the related capitalized costs are written off against accumulated amortization, or charged to earnings if there is a shortfall in accumulated amortization for the respective pool, when the determination is made.

Asset Retirement Obligations 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.

The liability amounts are based on future retirement cost estimates and incorporate many assumptions, such as time to abandonment. Over time, the liability is increased and expense is recognized for changes in its present value, and the initial capitalized cost is depreciated over the useful life of the asset.

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 the fair value of ARO as information about material changes to the liability become known. Revisions are recorded as an adjustment to existing ARO liabilities and to the carrying amount of the related assets. Revisions occurring at or near the end of an asset s useful life may result in a material positive or negative impact on 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 consisted primarily of financially-settled 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 at their grant date fair values under SFAS No.123 (revised 2004), Share-Based Payment (SFAS No. 123(R)). For 2008, share-based compensation totaled $6.6 million. We use the Black-Scholes option pricing model to estimate fair values of share-based awards consistent with the provisions of SFAS No. 123(R). 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 stock-based awards also impacts the amount of expense recorded over the expected life of the award.

We currently use historical volatility rather than implied volatility, which is based on options freely traded in the open market, as the activity level for traded options was not sufficient to estimate implied volatility in 2008. We use the midpoint scenario to estimate expected term allowed by the SEC s Staff Accounting Bulletin 107, in order to leverage as much actual exercise and post-vesting cancellation history as is available. 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.

Table of Contents

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 14 Income Taxes in Part II, Item 8 of this Annual Report for more information regarding our deferred taxes.

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

New Accounting Pronouncements

For information regarding new accounting pronouncements, see the information in Note 19 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. Changes in interest rates affect the interest earned on our cash and cash equivalents and the interest rate paid on borrowings under our bank credit facility and on the Floating Rate Notes. Currently, we do not use interest rate derivative instruments to manage exposure to interest rate changes. At December 31, 2008, $193 million of our long-term debt had variable interest rates while the remaining long-term debt had fixed interest rates. If the market interest rates had averaged 1% higher during 2008, interest rates for the period on variable rate debt outstanding during the period would have increased, and net loss before income taxes would have increased by approximately $1.6 million based on total variable debt outstanding during the period. If market interest rates had averaged 1% lower during 2008, interest expense for the period on variable rate debt would have decreased, and net loss before income taxes would have decreased by approximately $1.6 million.

Our credit standing and bond ratings impact the fair value and trading activity of our Senior Unsecured Notes. Recent trading activity in our Senior Unsecured Notes indicates that purchasers are requiring yields higher than 25%. The Senior Unsecured Notes have a contractual yield of 9.75%, for the Fixed Rate Notes, or less, for the Floating Rate Notes. As a result, if we were to attempt to issue new Senior Unsecured Notes with similar contractual terms as our existing Senior Unsecured Notes, our proceeds from issuance would be materially discounted from par value. Such a transaction would likely be uneconomical.

Table of Contents

Commodity Price Risk

Note 2 Summary of Significant Accounting Policies and Note 12 Derivative Transactions in Part II, Item 8 of this Annual Report describe our commodity price risks and the instruments we use to manage them.

The following table presents information related to our derivative contracts as of December 31, 2008:

Natural Gas Contracts

Remaining Contract Term	Contract Type	Floor/Ceiling-Floor ($/Mmbtu)	Volume (Mmbtu) Daily	Total	Total Fair Value (in thousands)
01/09 - 03/09	Collar	$ 6.75/$17.15	10,000	900,000	$ 969
04/09 - 06/09	Synthetic Put	$ 5.00/$10.00 - 11.00	10,000	910,000	$ (90)
11/09 - 01/10	Synthetic Put	$ 6.00/$10.00 - 11.00	10,000	920,000	$ (59)

Oil Contracts

Remaining Contract Term	Contract Type	Floor/Ceiling ($/Bbl)	Volume (Bbls) Daily	Total	Total Fair Value (in thousands)
1/09 - 06/09	Collar	$ 55.00/$87.17	3,000	543,000	$ 4,512

Table of Contents

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

Energy Partners, Ltd.:

We have audited Energy Partners, Ltd. and subsidiaries (the Company) internal control over financial reporting as of December 31, 2008, 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 maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control over Financial Reporting (Item 9A(b)). Our responsibility is to express an opinion on the Company s internal control over financial reporting 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 effective internal control over financial reporting was maintained in all material respects. Our audit 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 audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company s annual or interim financial statements will not be prevented or detected on a timely basis. Material weaknesses, as they relate to the following matters, have been identified and included in Management s Report on Internal Control over Financial Reporting appearing under Item 9A(b) of the Company s 2008 Annual Report on Form 10-K:

Control Environment over Financial Reporting

Complex or Non-Routine Accounting Matters

Period-End Financial Reporting Process

In our opinion, because of the effect of the aforementioned material weaknesses on the achievement of the objectives of the control criteria, Energy Partners Ltd. and subsidiaries has not maintained effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Energy Partners Ltd. and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations, changes in stockholders equity, and cash flows. These material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2008 consolidated financial statements, and this report does not affect our report dated August 3, 2009, which expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

New Orleans, Louisiana

August 3, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

Energy Partners, Ltd.:

We have audited the accompanying consolidated balance sheets of Energy Partners, Ltd. and subsidiaries (the Company) as of December 31, 2008 and 2007, and the related consolidated statements of operations, changes in stockholders equity, and cash flows for each of the years in the three-year period ended December 31, 2008. 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 audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. 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 audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Energy Partners, Ltd. and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 3 to the consolidated financial statements, the Company filed voluntary petitions on May 1, 2009 for reorganization under Chapter 11 of Title 11 of the United States Code, 11 U.S.C. §§ 101 et seq., as amended, in the United States Bankruptcy Court that raise substantial doubt about its ability to continue as a going concern. Management s plans in regard to these matters are also described in Note 3. The consolidated financial statements do not include any adjustments that might result from the outcome of this matter.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company s internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated August 3, 2009 expressed an adverse opinion on the effectiveness of the Company s internal control over financial reporting.

/s/ KPMG LLP

New Orleans, Louisiana

August 3, 2009

Table of Contents

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

December 31, 2008 and 2007

(In thousands, except share data)

	2008	2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,991	$ 8,864
Trade accounts receivable	29,264	47,081
Receivables from insurance	4,230	
Fair value of commodity derivative instruments	5,415	
Deferred tax assets		3,865
Prepaid expenses	4,522	6,698
Total current assets	45,422	66,508
Property and equipment, at cost under the successful efforts method of accounting for oil and natural gas properties	1,646,805	1,547,003
Less accumulated depreciation, depletion and amortization	(958,438)	(824,397)
Net property and equipment	688,367	722,606
Other assets	23,041	15,556
Deferred tax assets	1,580	
Deferred financing costs net of accumulated amortization of $3,780 and $2,100 at December 31, 2008 and 2007, respectively	8,356	10,186
	$ 766,766	$ 814,856
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 39,517	$ 14,369
Accrued expenses	63,973	100,007
Asset retirement obligations	18,181	4,548
Current portion of long-term debt	497,501	
Deferred tax liabilities	1,580	
Fair value of commodity derivative instruments	28	9,124
Total current liabilities	620,780	128,048
Long-term debt		484,501
Deferred tax liabilities		20,880
Asset retirement obligations	87,506	73,350
Fair value of commodity derivative instruments	55	4,602
Other	1,306	1,505
Commitments and contingencies		
	709,647	712,886
Stockholders equity:		
Preferred stock, $1 par value. Authorized 1,700,000 shares; no shares issued and outstanding		
Common stock, par value $0.01 per share. Authorized 100,000,000 shares; issued: 2008 44,323,293 shares; 2007 43,980,644 shares; outstanding, net of treasury shares: 2008 32,083,307 shares; 2007 31,740,658 shares	444	441

Additional paid-in capital	382,232	374,874
Accumulated deficit	(67,201)	(14,989)
Treasury stock, at cost, 2008 12,239,986 shares; 2007 12,239,986 shares	(258,356)	(258,356)
Total stockholders equity	57,119	101,970
	$ 766,766	$ 814,856

See accompanying notes to consolidated financial statements.

Table of Contents

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

Years Ended December 31, 2008, 2007 and 2006

(In thousands, except per share data)

	2008	2007	2006
Revenue:			
Oil and natural gas	$ 356,022	$ 454,340	$ 449,186
Other	230	309	364
	356,252	454,649	449,550
Costs and expenses:			
Lease operating	65,533	69,919	58,808
Transportation	1,089	2,441	2,028
Exploration expenditures and dry hole costs	30,199	98,209	51,745
Impairment of properties	110,403	114,913	84,680
Depreciation, depletion and amortization	103,318	170,083	198,162
Accretion of liability for asset retirement obligations	4,370	4,458	4,572
General and administrative	43,706	61,724	120,113
Taxes, other than on earnings	11,245	9,900	13,632
Gain on insurance recoveries		(8,084)	
(Gain) loss on sale of assets	(5,527)	(6,605)	969
Loss on abandonment	21,695	2,788	3,053
	386,031	519,746	537,762
Business interruption recovery	4,248	9,084	32,869
Loss from operations	(25,531)	(56,013)	(55,343)
Other income (expense):			
Interest income	784	1,585	1,428
Interest expense	(46,533)	(46,213)	(24,570)
Gain (loss) on derivative instruments	2,053	(13,083)	
Loss on early extinguishment of debt		(10,838)	
	(43,696)	(68,549)	(23,142)
Loss before income taxes	(69,227)	(124,562)	(78,485)
Income taxes	17,015	44,607	28,085
Net loss	(52,212)	(79,955)	(50,400)
Basic loss per share	$ (1.63)	$ (2.32)	$ (1.32)
Diluted loss per share	$ (1.63)	$ (2.32)	$ (1.32)
Weighted average common shares used in computing loss per share:			
Basic and diluted	31,988	34,501	38,313

See accompanying notes to consolidated financial statements.

Table of Contents

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY

Years Ended December 31, 2008, 2007 and 2006

(In thousands)

	Treasury Stock Shares	Treasury Stock	Common Stock Shares	Common Stock	Additional Paid In Capital	Accumulated Other Comprehensive Income	Retained Earnings (Deficit)	Total
Balance at December 31, 2005	3,474	$ (57,432)	41,467	$ 415	$ 348,863	$ (12,619)	$ 115,366	$ 394,593
Stock purchase, compensation and incentive plans, net	6	(8)	151	2	10,496			10,490
Exercise of common stock options			26		261			261
Conversion of warrants into common stock			834	8	1,825			1,833
Reclass of performance shares into equity					3,126			3,126
Comprehensive income:								
Net loss							(50,400)	(50,400)
Fair value of commodity derivative instruments						11,625		11,625
Comprehensive loss								(38,775)
Other			24		742			742
Balance at December 31, 2006	3,480	(57,440)	42,502	425	365,313	(994)	64,966	372,270
Stock purchase, compensation and incentive plans, net	1		181	4	6,870			6,874
Exercise of common stock options			44		468			468
Conversion of warrants into common stock			1,167	12	297			309
Purchase of shares into treasury	8,759	(200,916)						(200,916)
Comprehensive income:								
Net loss							(79,955)	(79,955)
Fair value of commodity derivative instruments						994		994
Comprehensive loss								(78,961)
Other			87		1,926			1,926
Balance at December 31, 2007	12,240	(258,356)	43,981	441	374,874		(14,989)	101,970
Stock purchase, compensation and incentive plans, net			116	1	4,789			4,790
Exercise of common stock options			79	1	749			750
Net loss							(52,212)	(52,212)
Other			147	1	1,820			1,821

Balance at December 31, 2008	12,240	$ (258,356)	44,323	$ 444	$ 382,232	$	$ (67,201)	$ 57,119

See accompanying notes to consolidated financial statements.

Table of Contents

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31, 2008, 2007 and 2006

(In thousands)

	2008	2007	2006
Cash flows from operating activities:			
Net loss	$ (52,212)	$ (79,955)	$ (50,400)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion and amortization	103,318	170,083	198,162
Accretion of liability for asset retirement obligations	4,370	4,458	4,572
Unrealized (gain) loss on derivative contracts	(19,058)	13,726	
Non cash compensation	5,276	8,521	11,038
Loss on early extinguishment of debt		3,398	
Deferred income taxes	(17,015)	(44,607)	(27,452)
(Gain) loss on disposal of assets and other	15,868	(5,083)	4,047
Exploration expenditures	21,796	87,102	38,288
Impairment of properties	110,403	114,913	84,161
Amortization of deferred financing costs	1,834	1,380	1,133
Gain on insurance recoveries		(8,084)	
Other	1,711	1,927	1,587
Changes in operating assets and liabilities:			
Trade accounts receivable	21,655	23,542	2,390
Other receivables	(4,249)	58,269	(8,966)
Prepaid expenses	2,276	1,930	(391)
Other assets	(5,819)	(2,529)	283
Accounts payable and accrued expenses	22,045	(51,449)	13,599
Other liabilities	(27,589)	(3,653)	23
Net cash provided by operating activities	184,610	293,889	272,074
Cash flows used in investing activities:			
Acquisition of business, net of cash acquired			(420)
Insurance recoveries for property, plant and equipment		19,574	
Property acquisitions	(20,925)	(7,346)	(15,897)
Exploration and development expenditures	(199,157)	(323,846)	(341,936)
Other property and equipment additions	(724)	(1,402)	(527)
Proceeds from sale of oil and gas assets	15,576	68,599	
Net cash used in investing activities	(205,230)	(244,421)	(358,780)
Cash flows provided by (used in) financing activities:			
Deferred financing costs	(5)	(11,178)	(853)
Repayments of long-term debt	(120,000)	(530,499)	(73,109)
Proceeds from long-term debt	133,000	698,000	155,000
Purchase of shares into treasury		(200,916)	
Exercise of stock options and warrants	752	775	2,093
Net cash provided by (used in) financing	13,747	(43,818)	83,131

Net increase (decrease) in cash and cash equivalents	(6,873)	5,650	(3,575)
Cash and cash equivalents at beginning of year	8,864	3,214	6,789
Cash and cash equivalents at end of year	$ 1,991	$ 8,864	$ 3,214

See accompanying notes to consolidated financial statements.

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization

The Company was incorporated as a Delaware corporation on January 29, 1998. We operate as an independent oil and natural gas exploration and production company. Our current operations are concentrated in the shallow to moderate depth waters in the Gulf of Mexico focusing on the areas of offshore Louisiana as well as the deepwater Gulf of Mexico in depths less than 5,000 feet.

On May 1, 2009, we and certain of our subsidiaries filed the Chapter 11 Cases in the Bankruptcy Court. We continue to manage our properties and operate our business as debtors-in-possession under the jurisdiction of the Bankruptcy Court. The Chapter 11 filings and related matters are addressed in Note 3 Subsequent Events, Liquidity and Capital Resources.

(2) Summary of Significant Accounting Policies

(a) Basis of Presentation

The consolidated financial statements 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.

(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.

Leasehold acquisition costs are capitalized. If proved reserves are found on an undeveloped property, leasehold costs are transferred to proved properties. Costs of undeveloped leases are recorded to expense over the lives of the leases. Capitalized costs of producing oil and natural gas properties are depreciated and depleted by the units-of-production method.

We assess the impairment of capitalized costs of proved oil and natural gas properties 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(c) Asset Retirement Obligations

We account for our AROs in accordance with Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations . SFAS No. 143 requires that we record 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. 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.

On January 1, 2007, we adopted the provisions of FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes . FIN 48 prescribes 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 and also provides guidance on derecognition, classification, interest and penalties. Under FIN 48, interest, if any, will be classified as a component of interest expense, and statutory penalties, if any, will be 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 available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed in the same manner as basic earnings per share except that the denominator is increased to include the number of additional common shares that could have been outstanding assuming the exercise of stock option awards and warrants and the potential shares associated with restricted share units and performance shares that would have a dilutive effect on earnings per share.

(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 receivables of $0.1 million and $0.2 million at December 31, 2008 and 2007, respectively, and had liabilities of $2.3 million and $2.9 million at December 31, 2008 and 2007, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(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, 2008 and 2007, cash and cash equivalents includes investments in overnight interest-bearing deposits of $4.1 million and $15.9 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. Special accounting for qualifying hedging activities allows gains and losses from derivative instruments to offset related results on the hedged item in earnings. For derivative instruments designated as cash-flow hedges, changes in fair value, to the extent the hedges are effective, are recognized in other comprehensive income (a component of stockholders equity) until the forecasted transaction is settled, when the resulting gains and losses are recorded in oil and natural gas revenue. Hedge ineffectiveness is measured at least quarterly based on the change in fair value of the derivative contract compared to that of the hedged item. Any change in fair value resulting from ineffectiveness is recorded to earnings. We accounted for our derivative instruments as qualifying hedging activities through April 2, 2007 when we elected to discontinue hedge accounting on our existing contracts and ceased designating hedging contracts that were entered into subsequent to that date as cash flow 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 subsequent to April 2, 2007 are also recognized in other income (expense).

(j) Stock-Based Compensation

Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123(R) using the modified prospective transition method. Under this method, stock-based compensation expense recognized includes (1) compensation expense for all stock-based compensation awards granted prior to, but not yet vested as of , January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, and (2) compensation expense for all stock-based compensation awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123(R). Additionally, SFAS No. 123(R) requires us to estimate pre-vesting option forfeitures at the time of grant and periodically revise those estimates in subsequent periods if actual forfeitures differ from those estimates. We record stock-based compensation expense only for those awards expected to vest using an estimated forfeiture rate based on our historical pre-vesting forfeiture data. We recognize stock-based compensation expense over the requisite service period during which each tranche of a stock-based award is earned.

In accordance with SFAS No. 123(R), we are required to report excess tax benefits from the exercise of stock options as financing cash flows. For the years ended December 31, 2008 and 2007, no excess tax benefits were reported in the statement of cash flows as we are in a net operating loss carryforward position. See Note 15 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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2008 our allowance for doubtful accounts was \$1.1 million, \$0.9 million of which was recorded as a reduction in earnings in 2008. At December 31, 2007, our allowance for doubtful accounts was \$0.2 million.

(l) 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 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 20.

(m) Reclassifications

Certain reclassifications have been made to the prior period financial statements in order to conform to the classification adopted for reporting in fiscal 2008.

(3) Subsequent Events, Liquidity and Capital Resources

Subsequent Events

As described in Note 1, on May 1, 2009, we filed the Chapter 11 Cases. On August 3, 2009, after a confirmation hearing in which the Bankruptcy Court considered the Plan and all objections thereto, it entered into a confirmation order and confirmed the Plan as of August 3, 2009. The primary purpose of the Plan is to effectuate a restructuring of our capital structure and improve cash flow and strengthen our balance sheet by reducing our overall indebtedness. Presently, we have a substantial amount of indebtedness outstanding (see Note 10).

The effectiveness of the Plan and our emergence from bankruptcy is subject to several conditions, including the successful closing of the Exit Facility. We are currently in negotiations with lenders on structuring the Exit Facility. Fore more information on the conditions to the effectiveness of the Plan see Item 1A Risk Factors.

Prior to the filing of the Chapter 11 Cases, a number of events and economic conditions which existed in 2008 negatively impacted our business and liquidity. These events included 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 have remained at low levels during 2009 relative to the levels reached in 2008; and

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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:

MMS Order and Term Sheet. As previously discussed, we received the MMS Order dated March 23, 2009. The MMS is part of the United States Department of the Interior. The MMS Order demanded that we provide to the MMS bonds or other acceptable security in the aggregate amount of $34.7 million to secure plugging and abandonment liabilities associated with all of our properties on federal leases in the Gulf of Mexico, with the first installment payment of $1.2 million due no later than March 31, 2009, an additional installment payment of $1.2 million due no later than June 30, 2009 and the remaining $32.3 million due no later than July 31, 2009. The MMS Order also required us to immediately shut-in production from all of our wells and facilities located in South Pass Blocks 27 and 28 in the federal portion of our East Bay field, while properly maintaining these facilities and wells with essential personnel. We promptly completed the shut-in of our federal East Bay facilities before the end of March 2009. Because federal leases would normally terminate if there is no production for 180 consecutive days, the affected leases could expire if (1) we do not comply with the requirements set forth by applicable MMS regulations and restore production to the shut-in federal leases by September 17, 2009; (2) we and the MMS do not otherwise come to an agreement that would prevent the leases from expiring on such date; or (3) there is no unitized production that would prevent the termination provisions in the affected leases from being triggered. The federal East Bay leases are included in production unit(s) covering portions of those leases and state leases in the East Bay field that continue to produce, which we believe may prevent the triggering of lease termination, although there is no assurance that this will be the case. The production from the wells and properties that we shut-in as a result of the MMS Order constituted less than 5% of our average daily production as of March 27, 2009. We also made two installment payments of approximately $1.2 million on March 30, 2009 and on April 29, 2009 in compliance with the MMS Order and the term sheet discussed below. We entered into a binding term sheet with the MMS on April 30, 2009 to establish terms for us to address our obligations under the MMS Order. Under the term sheet, we and the MMS have agreed to re-affirm the terms and conditions of the previously established trust account for the benefit of the MMS under the Decommissioning Trust Agreement dated December 23, 2008 among us, the MMS and JP Morgan Chase Bank, NA, and we had agreed to make monthly payments to the trust account in the amount of $1.2 million while the Chapter 11 Cases are pending and, on the effective date of the Plan to make a payment to the trust account equal to $21 million minus the aggregate amount of the monthly payments made into the trust account while the Chapter 11 Cases are pending (commencing with the payment made on April 29, 2009). The $1.2 million monthly payments to the trust account remain subject to approval by the Bankruptcy Court. All remaining amounts owed to the trust account to reach the full funding amount owed to the MMS of $36.1 million (after giving credit to all prior payments made by us) were payable in equal quarterly installments of approximately $1.2 million, commencing October 31, 2009, with quarterly payments continuing until full funding has occurred. On June 11, 2009, we received a letter from the MMS requesting an additional $10.95 million in financial assurance based on the actual costs for partial and completed well plugging and abandonment associated with our federal leases in the East Bay field. On June 24, 2009, we advised the MMS that we will provide the additional $10.95 million by increasing our quarterly payments identified in the term sheet such quarterly payments are presently contemplated to commence on October 31, 2009 which would increase the quarterly payments from approximately $1.2 million to approximately $1.8 million. The MMS has agreed to vote in favor of the Plan to the extent its treatment is consistent with the terms set forth in the term sheet. In addition, the MMS has granted a consensual stay of the MMS Order that will remain in place while the Chapter 11 Cases are pending. This stay, however, does not lift the requirement that our Federal wells and facilities located in South Pass Blocks 27 and 28 remain shut-in. The term sheet with the MMS contemplates that, on the effective date of the Plan, the MMS Order will be fully rescinded, and we will be allowed to resume production from these wells and facilities. However, the terms of the

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

term sheet, as incorporated into the Plan, will only supersede the MMS Order if the Bankruptcy Court confirms the Plan.

Reduction of Borrowing Base. In March 2009, we received a notice of redetermination from Bank of America, N.A., the Administrative Agent under the Credit Agreement, that our borrowing base under the Credit Agreement had been lowered from $150 million to $45 million, resulting in a borrowing base deficiency of $38 million. Following the receipt of this notice, we considered various alternatives provided for under the Credit Agreement to repay the borrowing base deficiency and presented to the Administrative Agent the proposal of an installment repayment plan. The Administrative Agent declined to approve our proposed repayment plan, and as a result, on March 24, 2009, we received a notice from the Administrative Agent requiring the lump-sum payment by us of $38 million to the Lenders by April 3, 2009. On April 3, 2009, we obtained a consent from the Required Lenders under the Credit Agreement, extending the due date for the repayment of the borrowing base deficiency until April 14, 2009. On April 14, 2009, we and the Required Lenders entered into a letter agreement that further extended the due date for repayment of the borrowing base deficiency until May 1, 2009 and provided that the Lenders agree not to exercise any rights and remedies until May 1, 2009 with respect to all outstanding and certain anticipated defaults by us under the Credit Agreement in exchange for our compliance with specified conditions. On May 1, 2009, we filed the Chapter 11 Cases.

Default on Senior Unsecured Notes. We were required to make annual interest payments of approximately $45.0 million each year on the Senior Unsecured Notes, of which $17 million was due on April 15, 2009, and remains unpaid. Our failure to make these interest payments within 30 days of the due date was an event of default under the indenture governing the Senior Unsecured Notes and under the cross-default provision of our Credit Agreement.

Surety Obligations. As of July 1, 2009, we had outstanding $60.0 million in surety bonds with four different indemnity companies. Our agreements with these indemnity companies allow them to demand cash reserves or letters of credit to support our outstanding surety bonds. In December 2008 and the first quarter of 2009, we posted cash collateral to restricted accounts for the benefit of certain of these indemnity companies totaling $5.7 million in response to requests to provide reserves against our surety bonds with them. If we default on some or all of these surety bonds, the indemnity companies may cancel our surety bonds. The cancelation of some or all of our surety bonds may result in violations of other agreements or obligations. As a result, we could be forced to shut in our production or lose our ability to continue to perform our business operations.

Plan of Reorganization; Plan Support and Lock-Up Agreement. On April 30, 2009, we entered into the Plan Support Agreement with the Consenting Holders of the outstanding principal amount of our Senior Unsecured Notes. The parties to the Plan Support Agreement had agreed, following receipt of the Disclosure Statement, to vote in favor of and support a plan or reorganization that is consistent in all material respects with the Term Sheet.

The Plan Support Agreement may be terminated under certain circumstances by the Majority Consenting Holders, including if (1) we fail to file the Plan or the Disclosure Statement with the Bankruptcy Court on or prior to May 15, 2009; (2) the Bankruptcy Court does not approve the Disclosure Statement on or prior to June 30, 2009; (3) the Bankruptcy Court does not confirm the Plan on or prior to August 15, 2009; (4) we do not consummate the restructuring transactions provided for in the Plan on or prior to September 10, 2009, or under certain circumstances, a later date; (5) we or any of our officers or directors fail to take any action required by the Plan Support Agreement in order to comply with our fiduciary obligations under applicable law or otherwise we file or support a plan of reorganization that is different from the Plan or withdraw or revoke the Plan; (6) we materially breach any of our obligations or fail to satisfy in any material respect any of the terms or conditions under the Plan Support Agreement; (7) our aggregate liabilities as of the dates specified in the Term Sheet (excluding those liabilities that would be extinguished by the Plan or otherwise do not survive the consummation

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of the Plan) materially exceed the amounts we represented in the Term Sheet; (8) an examiner with expanded powers relating to our business or trustee is appointed in any of the Chapter 11 Cases, any of the Chapter 11 Cases are converted to a case under Chapter 7 of the Bankruptcy Code or any of the Chapter 11 Cases are dismissed by the Bankruptcy Court; or (ix) any definitive documents executed by us in connection with the Chapter 11 Cases in order to implement the Plan are not consistent in all material respects with the terms set forth in the Term Sheet and otherwise are not reasonably satisfactory in all material respects to the Majority Consenting Holders. In any event, the Plan Support Agreement terminates on September 15, 2009.

Bankruptcy Proceedings, Plan of Reorganization, Exit Facility and Expected Emergence from Bankruptcy. On May 1, 2009, we and certain of our subsidiaries filed the Chapter 11 Cases with the Bankruptcy Court. We continue to manage our properties and operate our business as debtors-in-possession under the jurisdiction of the Bankruptcy Court. On June 11, 2009, as part of our Chapter 11 Cases, we filed the Plan with the Bankruptcy Court, and the Disclosure Statement, pursuant to which we solicited votes for the confirmation of the Plan. On July 31, 2009, we filed with the Bankruptcy Court the Plan, as modified as of July 31, 2009. The Plan was formulated after extensive negotiations with committees representing holders of the Senior Unsecured Notes and holders of our common stock interests. The primary purpose of the Plan is to effectuate a restructuring of our capital structure to strengthen our balance sheet by reducing our overall indebtedness and improve cash flow.

On July 23, 2009, we announced that the Plan had received the affirmative vote of the holders of our Senior Unsecured Notes and our 8.75% Senior Notes due 2010 and we consequently proceeded to request confirmation of the Plan from the Bankruptcy Court. On August 3, 2009, after a confirmation hearing in which the Bankruptcy Court considered the Plan and all objections thereto, it entered the Confirmation Order and confirmed the Plan as of August 3, 2009. The effectiveness of the Plan and our emergence from bankruptcy is subject to several conditions, including the successful closing of the Exit Facility. We are currently in negotiations with lenders on structuring the Exit Facility. For more information on the conditions to the effectiveness of the Plan see Item 1A Risk Factors.

The material terms of the Plan as confirmed by the Bankruptcy Court on August 3, 2009 include, among other things, that:

- each holder of the Senior Unsecured Notes and our 8.75% Senior Notes due 2010 would receive, in exchange for their total claim (including principal and interest), their pro rata share of 95% of New EPL Common Stock in us upon our emergence from bankruptcy;

- each holder of our common stock interests would receive, in exchange for their total claim, their pro rata share of 5% of New EPL Common Stock;

- upon the Effective Date, we shall have access to the Exit Facility in form and substance acceptable to us and the Majority Consenting Holders; and

- we may adopt the 2009 Long Term Incentive Plan under which it may issue shares of restricted new EPL common stock and new EPL stock options to certain of its employees and certain members of management;

- following the effective date of the reorganization, the sole equity interests in us would consist of (1) New EPL Common Stock issued to the holders of our Senior Unsecured Notes, the 8.75% Senior Notes due 2010, and holders of our common stock interests, (2) restricted new EPL common stock issued to certain members of our management, if any, and (3) new EPL stock options to be issued to certain key employees pursuant to the 2009 Long Term Incentive Plan, if any, which would be exercisable for new EPL common stock. Collectively, the restricted new EPL common stock issued pursuant to subparagraph (2) and the shares reserved for the exercise of new EPL stock options pursuant to subparagraph (3) above would in no event exceed 3% of the new EPL common stock on a fully diluted basis.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The timing and ultimate outcome of the Chapter 11 proceedings remain uncertain. Issues and matters to be resolved prior to emergence from the proceedings include negotiation of the Exit Facility.

Consummation of the Plan is conditioned upon, among other things, the closing of the Exit Facility. There can be no assurance that any or all of the foregoing conditions will be met (or waived) or that the other conditions to consummation, if any, will be satisfied. Accordingly, there can be no assurance that the Plan will be consummated and the restructuring completed.

Restructure of Prepetition Employee Arrangements. Prior to May 1, 2009, the Arrangements existed for certain of our employees that provided for such employees to receive cash payments and/or settlement of equity compensation awards either upon specified future vesting dates or in connection with a termination of employment. The Plan Support Agreement contains certain provisions that provide that such Arrangements must be amended, renegotiated, and/or restructured prior to the effective date of a confirmed plan of reorganization.

As a result of the Plan Support Agreement, the Board of Directors amended the provisions of the Severance Plan in a manner such that the protected employment period initiated by our change of control under such plans, as well as the severance benefits potentially payable in connection with certain terminations of employment during that protected period, would not be triggered by the restructuring contemplated by the Plan Support Agreement.

We also established the Retention Programs. In order for an office employee who participates in either of these programs to receive his or her retention payments, the participant has to waive and release any and all potential claims against the Company under the prepetition Arrangements.

Finally, the Severance Agreements with two of our executives were terminated by the Company and each of such executives in exchange for the executives receiving an unsecured claim for the rejection damages.

The total cost of the Retention Programs and the termination of the two Severance Agreements is approximately $2 million of which approximately $0.5 million has been paid during the bankruptcy proceedings and approximately $1.5 million will be paid when we emerge from bankruptcy.

NYSE Delisting. In March 2009, the NYSE notified us that our common stock had been suspended from trading and was subsequently delisted for failure to maintain the required market capitalization minimum criteria. Our common stock is being quoted for public trading on the Pink Sheets quotations system, an over-the-counter market, under the symbol ERPLQ.PK . This significantly impairs our ability to raise additional equity financing.

Changes to Production Levels. Due to our current liquidity situation and lower commodity prices, we expect to significantly reduce capital expenditures during 2009. As a result, we do not expect to be able to maintain our current production levels and we expect our production to decline significantly during the second half of 2009 primarily due to natural reservoir declines combined with minimal investment in reserve replacement activities. At our current and anticipated production levels, combined with the current and expected lower sales prices, we do not expect to have sufficient cash flows to fully fund our operations and meet all of our financial obligations in 2009 as discussed above.

Changes in the Board of Directors and Management. Our Board of Directors declined from eleven to five members during the first quarter of 2009. In addition, on March 1, 2009, Joseph T. Leary resigned as our Executive Vice President and Chief Financial Officer. On March 15, 2009, Richard A. Bachmann resigned as our Chairman and Chief Executive Officer and we engaged Alan D. Bell as our Chief Restructuring Officer.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Liquidity and Capital Resources

The above events and circumstances, together with the worldwide credit markets collapse in 2008 and the scarcity of available credit from most major commercial financial institutions, as well as the low trading price of our common stock, make it extremely difficult to find additional financing, either to refinance our Credit Agreement or our Senior Unsecured Notes or to provide additional liquidity during 2009.

Our financial statements reflect significant net losses in 2008, 2007 and 2006, an accumulated deficit of $67.2 million and a working capital deficit of $575.4 million as of December 31, 2008.

Our financial statements have been prepared on a going concern basis, which contemplates continuity of operations, realization of assets, and liquidation of liabilities in the ordinary course of business. As a result of defaults that occurred subsequent to December 31, 2008 with respect to the Credit Agreement, the Senior Unsecured Notes and the 8.75% Senior Notes due 2010, all of our indebtedness is classified in current liabilities as of December 31, 2008 (see Note 10). However, as a result of the Chapter 11 filings and related events, there is no assurance that the carrying amounts of assets will be realized or that liabilities will be liquidated or settled for the amounts recorded. While we expect consummation of the Chapter 11 proceedings to occur during 2009, the proceedings are not complete and involve inherent uncertainties, including uncertainties that are beyond our control. As a result, our independent public accountants, after considering the plans described above, advised us that they had reached a conclusion that such matters raise substantial doubt regarding our ability to continue as a going concern and, as required by auditing standards generally accepted in the United States, included in their auditors report on our 2008 financial statements an explanatory paragraph to reflect that conclusion.

(4) Common Stock

On March 12, 2007, our Board concluded our strategic alternatives process, as discussed in Note 6, which resulted in, among other things, an equity self-tender offer for up to 8,700,000 shares of our common stock at $23.00 per share and the authorization for the repurchase of up to $50 million of our common stock during the one year period following the completion of the equity self tender offer, subject to business and market conditions and any debt covenants restricting such repurchases. On April 23, 2007, we completed the equity self-tender offer and purchased 8,700,000 million shares of our common stock. In addition, during the year ended December 31, 2007, pursuant to our stock repurchase program we acquired 59,500 shares of our common stock for $0.8 million, an average price of $13.71 per share. All of these shares are reflected in treasury stock in the Consolidated Balance Sheets.

(5) Supplemental Cash Flow Information

The following is supplemental cash flow information:

	Years Ended December 31,		
	2008	2007	2006
	(In thousands)		
Interest paid	$ 46,875	$ 42,982	$ 23,084
Income taxes paid, net of refunds	$	$	$ 350

The following is supplemental disclosure of non-cash financing activities:

	Years Ended December 31,		
	2008	2007	2006
	(In thousands)		
Restricted share units	$ 487	$ 1,010	$ 879

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(6) Mergers, Acquisitions and Dispositions

In March 2008, we completed the sale of two Gulf of Mexico Shelf properties located in our Western offshore area for $15.0 million after giving effect to preliminary closing adjustments. We recorded a gain on the sale of $7.1 million.

In June 2007, we sold substantially all of our onshore South Louisiana producing assets for approximately $68.6 million in cash, after closing adjustments. We used the proceeds to pay down a portion of our revolving credit facility. The estimated proved reserves of the disposed properties were approximately 2.1 Mmboe. We recorded a gain of $6.5 million on the sale.

In April 2007, we repurchased 8,700,000 shares of our common stock at $23.00 per share, refinanced our revolving credit facility and acquired substantially all of our existing $150 million aggregate principal amount 8.75% Senior Notes due 2010 pursuant to the Transactions. We sold selected properties following the completion of the Transactions to reduce debt under our new bank credit facility. In order to fund the Transactions, we undertook a private offering of $450 million in aggregate principal amount of the Senior Unsecured Notes and entered into a new bank credit facility. In conjunction with the termination of a previous plan of merger with Stone, we paid to Stone $8.0 million, which was included in G&A expenses in the fourth quarter of 2006. In addition, a $43.5 million termination fee that was advanced to Plains in June 2006 on behalf of Stone was expensed in 2006 along with other merger and strategic alternatives related costs of $15.0 million. We incurred $9.4 million of financial and legal advisory fees during 2007 related to these activities.

In connection with an acquisition in 2002, we issued, among other things, warrants to purchase four million shares of our common stock in the same acquisition. Of the warrants, one million had a strike price of $9.00 and three million had a strike price of $11.00 per share. The warrants became exercisable on January 15, 2003 and expired on January 15, 2007. All remaining warrants were converted during the first quarter of 2007. In addition, former preferred stockholders of the acquired company had the right to receive contingent consideration based upon a percentage of the amount by which the before tax net present value of proved reserves related, in general, to exploratory prospect acreage held by the acquired company as of the closing date of the acquisition exceeded the net present value discounted at 30%. The potential consideration was determined annually from March 3, 2003 until March 1, 2007. We capitalized, as additional purchase price, all contingent consideration payments all of which were made in cash and totaled $4.3 million. As of March 1, 2007, the final determination date, we determined that no final payment was due.

(7) Property and Equipment

The following is a summary of property and equipment at December 31, 2008 and 2007:

	2008	2007
	(In thousands)	
Proved oil and natural gas properties	$ 1,601,748	$ 1,496,068
Unproved oil and natural gas properties	36,274	42,083
Other	8,783	8,852
	$ 1,646,805	$ 1,547,003

Substantially all of our oil and natural gas properties serve as collateral for our Credit Agreement.

We recognized impairment expense of $110.4 million, $114.9 million and $84.7 million in the years ending December 31, 2008, 2007 and 2006, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During 2008, we recorded impairments of oil and natural gas properties totaling $110.4 million. The impairment expense was primarily related to certain deepwater prospects ($47.5 million), producing fields (primarily five) which were determined to have future net cash flows less than their carrying values due primarily to commodity price declines and reservoir performance resulting in the write down of these properties to their estimated fair values as of December 31, 2008 ($39.3 million) and certain undeveloped properties ($20.8 million).

During 2007, we recorded impairment expense related to 17 fields. Eight fields with a net book value of $79.4 million experienced mechanical difficulties or facility requirements and we determined that significant capital would be needed to extend their economic lives. With our decreased capital budget for 2008, we determined that this capital would be better deployed to projects with more potential. Another six fields with a net book value of $15.9 million underperformed and fully depleted earlier than anticipated. We determined that the remaining three fields had future projected cash flows of less than their net book values due to performance issues and reserve revisions and therefore recorded impairment charges related to these fields totaling $19.6 million to write them down to their fair values during 2007.

Substantially all of the impairment expense in 2006 was taken in eight fields, four of which were onshore assets acquired during an acquisition in January of 2005. Three of these onshore fields along with three offshore fields experienced downward revisions of recoverable reserves at December 31, 2006. These revisions along with decreased natural gas prices resulted in impairment charges of $52.1 million on these assets. We elected to release the lease on the remaining onshore field. Additionally, one other offshore field experienced mechanical difficulties and we determined that significant capital would be needed to extend its economic life and that this capital would be better deployed to projects with more potential. Therefore, we wrote off the net book value of these assets of $27.0 million during 2006.

We capitalize exploratory well costs until we determine that the well has found proved reserves or is deemed noncommercial, in which case the well costs are immediately charged to exploration expense. Changes in exploratory well costs that were capitalized for a period of greater than one year, excluding amounts that were capitalized and subsequently expensed in the same period, are as follows:

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Capitalized exploratory well costs, beginning of period	$ 32,612	$ 28,984	$
Additions to capitalized exploratory well costs pending determination of proved reserves		3,628	28,984
Capitalized exploratory well costs charged to expense	(32,612)		
Capitalized exploratory well costs, end of period	$	$ 32,612	$ 28,984

At December 31, 2008, we did not have any projects that were suspended for a period greater than one year. At December 31, 2007, we had two projects whose exploratory well costs were suspended and were capitalized for a period greater than one year in the amount of $32.6 million. At December 31, 2006, we did not have any projects that were suspended for a period greater than one year.

(8) Tropical Weather

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. We maintain insurance coverage for property damage due to windstorms with a deductible of $10 million for each hurricane. We also maintain business interruption insurance on a portion of our lost revenue on our South Timbalier 41, 42 and 46 properties. Recovery of lost revenue from

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 is recorded in other receivables at December 31, 2008. All of these amounts were collected in 2009.

As a result of Hurricanes Katrina and Rita and three other hurricanes that traversed the Gulf of Mexico and adjacent land areas in 2005, nearly all of our production was shut in at one time or another during the three months ended September 30, 2005 and into 2006. We maintained business interruption insurance during this period on our significant properties, including our East Bay field on which recovery of lost revenue continued to accrue until October 2006. Through March 31, 2007, the total business interruption claim on these fields was $62.6 million (all of which had been collected as of that date). In the first quarter of 2007, we settled and collected all remaining claims related to Hurricanes Katrina and Rita and recognized business interruption income of $9.1 million and a gain of $8.1 million on a property damage settlement.

(9) Asset Retirement Obligations

We record the fair value of a liability for an ARO 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 the asset retirement obligations:

	Asset Retirement Obligations	
	2008	2007
	(in thousands)	
Beginning of period total	$ 77,898	$ 68,767
Accretion expense	4,370	4,457
Sale of properties	(1,821)	
Revisions	36,444	3,809
Liabilities incurred	13,385	4,409
Liabilities settled	(24,589)	(3,544)
End of period total	105,687	77,898
Less: End of period current portion	(18,181)	(4,548)
End of the period noncurrent portion	$ 87,506	$ 73,350

During 2008, we began to plug and abandon a significant number of wellbores and began decommissioning associated with platforms, structures, pipelines and facilities on leases in the Gulf of Mexico that are no longer producing and were required, in most instances, to be performed during that period under MMS requirements. The level of abandonment activity we performed in 2008 was significantly higher than in any past period and was performed at a high pricing point in the market for such services with equipment, in some cases, that exceeded the capability of less costly equipment capable of performing such operations. Further, because we performed this work at a suboptimal time of the year, we were significantly impacted by weather delays. We incurred costs significantly in excess of our recorded ARO for this work. As a result of this experience, and our cost experience on other 2008 abandonment activities, as well as our efforts to estimate our planned work for 2009, we revised our estimated abandonment costs where appropriate to reflect recent experience in determining the estimated fair value of our abandonment obligations. The total impact of our revisions to ARO for 2008 resulted in a loss on abandonment of $21.7 million. Revisions to ARO that did not result in an impact to 2008 earnings were recorded as additions to our oil and natural gas properties account and are amortized over remaining units-of-production.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(10) Indebtedness

See Note 3 Subsequent Events, Liquidity and Capital Resources for additional information on our indebtedness and the impact of the Chapter 11 Cases on the Credit Agreement, the Senior Unsecured Notes and the 8.75% Senior Notes due 2010.

In April 2007, we refinanced our bank credit facility with the Credit Agreement, which had an initial availability of $225 million and a borrowing base of $200 million. Concurrently with the sale of assets described in Note 6, the availability under the Credit Agreement was automatically reduced to the $200 million borrowing base amount. The Credit Agreement is secured by substantially all of our assets. The borrowing base under the Credit Agreement is subject to redetermination based on the proved reserves of the oil and natural gas properties that serve as collateral as set out in the reserve report delivered to the banks in April and October. We and our group of Credit Agreement participants each may request one additional redetermination each calendar year.

In November 2008, our Credit Agreement was redetermined with a borrowing base of $150 million. At December 31, 2008, we had $43 million outstanding under the Credit Agreement. In March 2009, the administrative agent for the Credit Agreement notified us that the semi-annual redetermination of our borrowing base pursuant to the Credit Agreement had occurred, resulting in a new borrowing base of $45 million. We had $83 million outstanding under the 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 Credit Agreement as of December 31, 2008, we subsequently failed to timely satisfy a number of 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.

Prior to the redetermination of our borrowing base in March 2009 and the commencement of the Chapter 11 Cases, the Credit Agreement permitted both prime rate borrowings and LIBOR borrowings plus a floating spread. The spread floated up or down based on utilization of the Credit Agreement. Under the terms of the Credit Agreement, the interest rate spread ranged from 1.00% to 2.5% above LIBOR and 0% to 0.50% above prime. In addition we paid an annual fee on the unused portion of the facility, ranging between 0.25% to 0.50% based on utilization. The Credit Agreement contained customary events of default and various financial covenants, which required us to maintain: (1) a minimum current ratio, as defined by the Credit Agreement, of 1.0x, (2) a minimum Consolidated EBITDAX to interest ratio, as defined by the Credit Agreement, of 2.5x, and (3) a ratio of long-term debt to Consolidated EBITDAX below 3.0. Our failure to cure the borrowing base deficiency by May 1, 2009 constituted an event of default under our bank credit facility. Subsequent to such date, we have been paying interest at the foregoing rates plus 2.00% per annum (the default rate).

The current ratio, as defined by the Credit Agreement, includes (among other terms) in current assets our unused availability on the Credit Agreement for purposes of satisfying the minimum current ratio covenant. As a result, for purposes of complying with the minimum current ratio covenant at each quarterly compliance reporting date, our working capital deficit, as adjusted by the terms of the Credit Agreement, reduces the amount available for borrowings under the Credit Agreement.

In April 2007, we completed an offering of the Senior Unsecured Notes, consisting of $300 million aggregate principal amount of the Fixed Rate Notes, with interest payable semi-annually on April 15 and October 15 beginning on October 15, 2007, and $150 million aggregate principal amount of the Floating Rate Notes. The interest rate on the Floating Rate Notes for a particular interest period is an annual rate equal to the three-month LIBOR plus 5.125%. Interest on the Floating Rate Notes is payable quarterly on January 15, April 15, July 15 and October 15, beginning in July of 2007. We may redeem the Senior Unsecured Notes, in whole or in part, prior to their maturity at specific redemption prices including premiums ranging from 4.875% to 0% from 2011 to 2013 and thereafter for the Fixed Rate Notes and premiums ranging from 2% to 0% from 2008

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

to 2010 and thereafter for the Floating Rate Notes. The indenture governing the Senior Unsecured Notes contains covenants, including but not limited to a covenant limiting the creation of liens securing indebtedness. The Senior Unsecured Notes are not subject to any sinking fund requirements. In November 2007, we consummated an exchange offer pursuant to which we exchanged registered senior unsecured notes having substantially identical terms as the privately placed Senior Unsecured Notes.

In May 2007, we completed a cash tender offer for the $150 million 8.75% Senior Notes due 2010. Approximately $145.5 million of the 8.75% Senior Notes due 2010 were repurchased and substantially all of their covenants have been removed.

During the year ended December 31, 2007, we recorded a loss on early extinguishment of debt for the refinancing of the Credit Agreement and the repurchase of the 8.75% Senior Notes due 2010 totaling approximately $10.8 million. This loss included the write-off of unamortized deferred financing costs related to the Credit Agreement and the 8.75% Senior Notes due 2010 as well as consent fees related to the tender for the 8.75% Senior Notes due 2010.

At December 31, 2008 and 2007, our indebtedness was as follows:

	2008	2007
	(In thousands)	
Fixed Rate Notes, annual interest of 9.75%, payable May 15, 2014	$ 300,000	$ 300,000
Floating Rate Notes, with weighted average interest on December 31, 2008, of 9.94%, payable April 15, 2013	150,000	150,000
Senior Notes, annual interest of 8.75%, payable August 1, 2010	4,501	4,501
Credit Agreement, interest rate based on LIBOR borrowing rates plus a floating spread payable April 23, 2011, with weighted average interest on December 31, 2008 of 2.57%	43,000	30,000
	497,501	484,501
Less: Current maturities	497,501	
	$	$ 484,501

(11) Significant Customers

We had oil and natural gas sales to three customers accounting for 38%, 24% and 23%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2008. We had oil and natural gas sales to three customers accounting for 29%, 27% and 14%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2007. We had oil and natural gas sales to four customers accounting for 28%, 19%, 12% and 11%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2006.

(12) Derivative Transactions

We enter into derivative transactions to reduce exposure to fluctuations in the price of oil and natural gas for a portion of our production. Our contracts limit our exposure to declines in the sales price of oil or natural gas for a limited amount of production. Some contracts also limit our ability to benefit from increases in the sales price of oil or natural gas. Our Board of Directors has set limitations on the percentage of proved production that we can make subject to these contracts. Our oil contracts are primarily settled based on the average of the reported settlement prices for West Texas Intermediate crude on the NYMEX for each month. Our natural gas contracts are primarily settled based on the average of the last three days of trading of the NYMEX Henry Hub natural gas contract each month. All of our existing contracts are with major financial institutions which are also parties to the Credit Agreement.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We primarily use financially-settled oil and natural gas zero-cost collars, put options and call options to provide varying upside price participation and downside price protection for a portion of our expected production. With a zero-cost collar, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price of the collar, and we are required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price of the collar. With a put option, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the strike price of the put and we have no obligation to the counterparty except for the payment of any option premium. Our synthetic put option agreements consist of a combination of sales and purchases of put and call contracts covering the same production. With these agreements, we reduce the per unit premium cost of the agreement by allowing the counterparty to take a limited amount of the benefit of price increases, while we retain the benefit over a stated settlement price. On occasion, we have incorporated floors and/or collars into our production sales contracts which are settled under conventional marketing terms.

Prior to the second quarter of 2007, all derivative transactions that qualified for hedge accounting under SFAS No. 133 were designated on the date we entered into each transaction as a hedge of the variability in cash flows associated with the forecasted sale of future oil and natural gas production. After-tax changes in the fair value of a hedge that was highly effective and designated and qualified as a cash flow hedge, to the extent that the hedge was effective, was recorded as Accumulated Other Comprehensive Income (OCI) on the consolidated balance sheet until the sale of the hedged oil and natural gas production occurred. Upon the sale of the underlying hedged production, the net after-tax change in the fair value of the associated hedging transaction recorded in OCI was reversed and the resulting gain or loss on the settlement of the hedge, to the extent that it was effective, was reported in oil and natural gas revenues in the consolidated statement of operations. On April 1, 2007, hedge accounting was discontinued prospectively for existing contracts and, until settled, all subsequent changes in fair value are recognized in earnings in the period in which the change occurs. At March 31, 2007, we had a $1.5 million after-tax net loss recorded in OCI.

Effective April 2, 2007, we elected to discontinue hedge accounting on our existing contracts and elected not to designate any additional derivative contracts that were entered into subsequent to that date as cash flow hedges under SFAS No. 133 as amended. Derivative contracts are carried at their fair value on the consolidated balance sheet as Fair value of commodity derivative instruments and all unrealized gains and losses are recorded in Gain (loss) on derivative instruments in Other income (expense) in the consolidated statement of operations and realized gains and losses related to contract settlements subsequent to April 2, 2007 are also recognized in the same line item in Other income (expense) in the consolidated statement of operations.

We had the following derivative contracts as of December 31, 2008:

Natural Gas Contracts

		Floor/Ceiling-Floor	Volume (Mmbtu)	
Remaining Contract Term	**Contract Type**	**($/Mmbtu)**	**Daily**	**Total**
01/09 - 03/09	Collar	$ 6.75/$17.15	10,000	900,000
04/09 - 06/09	Synthetic Put	$ 5.00/$10.00 - 11.00[1]	10,000	910,000
11/09 - 01/10	Synthetic Put	$ 6.00/$10.00 - 11.00[1]	10,000	920,000

Oil Contracts

		Floor/Ceiling	Volume (Bbls)	
Remaining Contract Term	**Contract Type**	**($/Bbl)**	**Daily**	**Total**
1/09 - 06/09	Collar	$ 55.00/$87.17	3,000	543,000

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Subsequent to December 31, 2008, we entered into the following derivative contracts:

Natural Gas Contracts

Remaining Contract Term	Contract Type	Floor/Ceiling-Floor ($/Mmbtu)	Volume (Mmbtu) Daily	Total
11/09 - 01/10	Synthetic Put	$ 5.83/$10.00 - 11.00[1]	15,000	1,380,000

(1) The counterparty pays us if the settlement price for the settlement period is below the floor. We pay the counterparty the amount by which the settlement price exceeds $10.00/Mmbtu for the settlement period, such payment being limited to the spread from $10.00/Mmbtu to $11.00/Mmbtu (or $1.00/Mmbtu). We benefit fully from settlement prices in excess of $11.00/Mmbtu.

During March and May 2009, the counterparties to all of the remaining open contracts exercised their right to settle the then outstanding contracts for net cash payments to us totaling $4.1 million. We recorded a net gain on the settlement of our derivative contracts of $ 2.7 million in 2009.

The following table presents information about the components of gain (loss) on derivative instruments for the years ended December 31, 2008 and 2007.

	2008	2007
Derivative contracts:		
Unrealized gain (loss) due to change in fair market value	$ 19,057	$ (13,726)
Realized gain (loss) on settlement	(17,004)	643
Total gain (loss) on derivative instruments	$ 2,053	$ (13,083)

For the year ended December 31, 2006, under cash flow hedge accounting, settlements of hedging contracts reduced oil and natural gas revenues by $0.7 million.

The following table reconciles the change in accumulated other comprehensive income for the year ended December 31, 2007:

	Year Ended December 31, 2007 (In thousands)	
Accumulated other comprehensive loss as of December 31, 2006 net of taxes of $558		$ (994)
Net loss	$ (79,955)	
Other comprehensive income net of tax		
Hedging activities		
Reclassification adjustments for settled contracts net of taxes of $90	(161)	
Changes in fair value of outstanding hedging positions net of taxes of $(649)	1,155	
Total other comprehensive income	994	994
Comprehensive loss	$ (78,961)	

Accumulated other comprehensive income as of December 31, 2007	$

For the year ended December 31, 2008, our comprehensive loss is equal to our net loss of $52.2 million.

(13) Fair Value Measurements

The following tables provide fair value measurement information for our assets and liabilities reported at fair value in the accompanying Consolidated Balance Sheets as of December 31, 2008. At December 31, 2008,

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the carrying values of cash and cash equivalents, trade accounts receivable and accounts payable (including income taxes payable and accrued expenses) approximated fair value and are not presented in the table.

	As of December 31, 2008				
			Fair Value Measurements Using:		
	Carrying Amount	Total Fair Value	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Financial Assets (Liabilities) (in thousands):					
Oil and natural gas puts and collars	$ 5,332	$ 5,332	$	$ 5,332	$
Debt	$ (497,501)	$ (191,281)	$	$ (191,281)	$

SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the table above, this hierarchy consists of three broad levels. Level 1 inputs on the hierarchy consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are other than quoted prices in active markets included in Level 1. Level 3 inputs have the lowest priority and include significant inputs that are generally less observable from objective sources. When available, we measure fair value using Level 1 inputs because they generally provide the most reliable evidence of fair value. We currently do not use Level 3 inputs to measure fair value.

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Level 2 Fair Value Measurements

Debt At December 31, 2008, the Fixed Rate Notes and the Floating Rate Notes were not actively traded in an established market. Therefore, quoted prices were not available. However, we estimated the fair values of these debt instruments based on prices reflected by trades which occurred near December 31, 2008 as obtained through financial information services. The fair value of the Credit Agreement is estimated to approximate the carrying amount because the interest rates paid on such debt are generally set for periods of three months or less.

Oil and natural gas puts and collars The fair values of the oil and natural gas puts and collars are estimated using similar, observable NYMEX published settlements.

(14) Income Taxes

Components of income tax benefit for the years ended December 31, 2008, 2007 and 2006 are as follows:

	Current	Deferred	Total
		(In thousands)	
2008:			
Federal	$	$ 16,542	$ 16,542
State		473	473
	$	$ 17,015	$ 17,015
2007:			
Federal	$	$ 43,368	$ 43,368
State		1,239	1,239

	$	$ 44,607	$ 44,607
2006:			
Federal	$ 633	$ 26,672	$ 27,305
State		780	780
	$ 633	$ 27,452	$ 28,085

82

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The reasons for the differences between the effective tax rates and the expected corporate federal income tax rate are as follows:

	Percentage of Pretax Earnings		
	2008	2007	2006
Expected tax rate	35.0%	35.0%	35.0%
State taxes	1.0	1.0	1.0
Valuation allowance	(10.8)		
Other	(0.6)	(0.2)	(0.2)
	24.6%	35.8%	35.8%

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, 2008 and 2007 are presented below:

	2008	2007
	(In thousands)	
Current deferred tax assets (liabilities):		
Fair value of commodity derivative instruments	$ (1,636)	$ 3,285
Accrued bonus compensation	56	580
Net current deferred tax asset (liability)	$ (1,580)	$ 3,865
Non-current deferred tax assets:		
Restricted stock awards and options	$ 6,268	$ 5,033
Federal and state net operating loss carryforwards	65,953	53,692
Fair market value of commodity derivative instruments	24	1,657
Other	741	
Valuation allowance	(7,465)	1,465
Non-current deferred tax asset	65,521	61,847
Non-current deferred tax liabilities:		
Property, plant and equipment, principally due to differences in depreciation	(63,941)	(82,727)
Net non-current deferred tax asset (liability)	$ 1,580	$ (20,880)

At December 31, 2008, we had net operating loss carryforwards (NOLs) of approximately $183 million, which are available to reduce future federal taxable income. The NOLs begin expiring in the years 2018 through 2028. The 2008 tax provision does not use any of the NOLs. The amount of our NOLs, and possible certain other tax attributes, may be significantly reduced upon implementation of the Plan. In addition, the Reorganized Company s subsequent utilization of any built-in losses with respect to its assets and NOLs remaining, and possibly certain other tax attributes, may be restricted as a result of and upon implementation of the Plan.

In 2008, our net deferred tax position changed from a net deferred tax liability position to a net deferred tax asset position. Our assessment of the need for a valuation allowance, as required by SFAS No. 109, was based primarily on a three year trend of significant net losses in 2008, 2007 and 2006, and the precipitous decline and continued weakness in oil and natural gas prices as of December 31, 2008 and continuing into 2009. We are not able to conclude that it is more likely than not that all of the deferred tax assets will be realized through future earnings and reversal of taxable temporary differences. As a result, we have provided a valuation allowance of $7.5 million, reducing our net deferred tax asset to zero. A return to profitability would provide a basis for reversal of a portion of the valuation allowance relating to realized deferred tax assets.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of January 1, 2009, our 2004-2008 income tax years remain subject to examination by the Internal Revenue Service, as well as the Louisiana Department of Revenue. In addition, Texas Franchise Tax calendar years 2003-2008 remain subject to examination.

(15) Employee Benefit Plans

See Note 3 Subsequent Events, Liquidity and Capital Resources Subsequent Events Restructure of Prepetition Employee Arrangements for a description of certain of the plans described below that were restructured subsequent to December 31, 2008.

At December 31, 2008, we have two stock-based compensation plans which are long term-incentive plans authorizing various types of market and performance based incentive awards to be granted to officers and employees. The 2006 Long Term Stock Incentive Plan (the Employee Plan) provides for the grant of stock options for which the exercise price, set at the time of the grant, is not less than the fair market value per share at the date of grant. The outstanding options have a term of 10 years and generally vest over three years with grants to a limited group of people that cliff vest at the end of five years. The Employee Plan also provides for restricted stock and restricted share units, which are referred to as non-vested share awards under SFAS No. 123(R), and performance share awards. The Employee Plan was adopted by the Board of Directors in March 2006 and approved by stockholders in May 2006 and is administered by the Compensation Committee of the Board of Directors or such other committee as may be designated by the Board of Directors. The Compensation Committee is authorized to select the employees who will receive awards, to determine the types of awards to be granted to each person, and to establish the terms of each award. The total number of shares that may be issued under the plan for all types of awards was 2,604,414 as of May 2006.

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 permits 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 number of shares authorized for issuance under the Director Plan is 500,000. The size of any grants of stock options and restricted share units to non-employee directors, including to new directors, will be determined annually, based on the analysis of an independent compensation consultant. The option exercise price for an option granted under the Director Plan shall be the fair market value of the shares covered by the option at the time the option is granted. Options become fully exercisable on the first anniversary of the date of the grant. Prior to the one-year anniversary, the options shall be 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 has not become exercisable prior to the cessation of the optionee s service as a director for any reason shall not thereafter become exercisable. Each option shall expire on the earlier of (1) 10 years from the date of the granting thereof, or (2) 36 months after the date the optionee ceases to be a director of the Company for any reason. Each restricted share unit represents 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 shall become 100% vested in a grant of restricted share units on the first anniversary of the date of grant. Prior to the first anniversary of the grant, an eligible director shall be vested in a number of restricted share units determined by pro-rating the grant based on the number of days elapsed since the date of the grant. If the service of an eligible director ceases for any reason prior to the first anniversary of the grant, other than in connection with the occurrence of a change of control of the Company, the director shall forfeit any unvested restricted share units.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table reports stock-based compensation expense and related tax benefits recognized for the years ended December 31, 2008, 2007 and 2006:

	2008	2007 (in thousands)	2006
Compensation Expense (Benefit):			
Option shares	$ 2,127	$ 3,690	$ 4,391
Non-vested share awards	3,440	5,415	5,933
Performance share awards	(293)	(901)	828
Amount related to options granted prior to January 1, 2006 (included in option share expense above)	474	1,481	2,415
Deferred Income Tax Benefit	1,899	2,953	4,005

The fair value of each share option award is estimated on the date of grant using the Black-Scholes option valuation model with the following weighted average assumptions for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31, 2008	2007	2006
Black-Scholes option pricing model assumptions:			
Risk free interest rate	4.5%	4.5%	4.4%
Expected life (years)	4.95	4.95	4.79
Expected volatility	38%	37%	43%
Dividend yield			

Expected volatility is based on the historical volatility of our stock over the period of time equivalent to the expected term of the options granted. The expected term of options granted is derived from historical exercise patterns over a period of time with consideration of expected term of unvested options. We have not experienced significant differences in the historical exercise patterns among officers, employees and non-employee directors for them to be considered separately for valuation purposes. 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.

A summary of option share activity for the year ended December 31, 2008 is as follows:

	Options	Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contractual Terms (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding on December 31, 2007	2,243,725	$ 16.71		
Granted	257,197	11.16		
Exercised	(77,833)	9.66		
Forfeited/Cancelled	(83,170)	22.72		
Outstanding on December 31, 2008	2,339,919	$ 16.12	5.08	$ 37,719
Exercisable on December 31, 2008	1,620,321	$ 15.34	4.23	$ 24,856
Available for future grants on December 31, 2008	2,685,256			

The weighted-average grant-date fair value of option shares granted during the years ended December 31, 2008, 2007 and 2006 was $4.53, $6.16 and $9.24, respectively. The aggregate intrinsic value of option shares

85

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(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) exercised during the years ended December 31, 2008, 2007 and 2006 was $0.4 million, $0.4 million and $0.4 million, respectively.

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 years ended December 31, 2008, 2007 and 2006 was $12.50 per share, $17.76 per share, and $21.62 per share, respectively. The total fair value of non-vested share awards that vested during each of the years ended December 31, 2008, 2007 and 2006 was $2.4 million, $3.6 million and $3.3 million, respectively. A summary of the activity related to our non-vested share awards for the year ended December 31, 2008 is as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Non-vested share awards outstanding at December 31, 2007	602,398	$ 21.09
Granted	137,728	12.50
Vested	(213,480)	11.24
Forfeited/Cancelled	(92,946)	23.99
Non-vested share awards outstanding at December 31, 2008	433,700	$ 20.22

During the period from 2003 through 2005, performance shares were awarded to officers and key employees with the number of shares to be issued upon being earned, at the end of their respective three year cycles, being based on certain performance measures. The shares awarded could range from a minimum of 0% to a maximum of 200% of the target number of shares depending on the level at which the goals were attained. We did not award any performance shares in 2006, 2007 or 2008. In the year ended December 31, 2006, 55,111 shares were earned and issued and 35,756 shares expired unearned or were forfeited. In the year ended December 31, 2007, 69,000 shares were earned and issued and 56,100 expired unearned or forfeited leaving 80,990 shares reserved based on the maximum award available. In the year ended December 31, 2008 all remaining available awards expired unearned.

As of December 31, 2008, $1.4 million of total unrecognized compensation expense related to outstanding option shares was expected to be recognized over a weighted-average period of 1 year. As of December 31, 2008, $3.0 million of total unrecognized compensation expense related to non-vested share awards was expected to be recognized over a weighted-average period of 1 year.

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 common stock of EPL until 2009. We made matching contributions to the 401(k) Plan of 266,365, 57,634 and 38,220 shares of common stock in 2008, 2007 and 2006 valued at approximately $0.9 million, $0.9 million and $0.9 million, respectively. During 2009, our 401(k) Plan was amended to require matching contributions to be made in cash.

2008 Key Employee Retention Plan

The Compensation Committee and the Board of Directors approved a retention plan for a limited group of key employees, which group excludes executive officers, providing for annual cash payments in December 2009, 2010 and 2011 of 20%, 30% and 50%, respectively, of the employees annual base salaries. Participants must be employed as of the vesting date to earn the retention award. This plan was effective December 1, 2008. Estimated payments under this plan for 2009, 2010 and 2011 are $0.8 million, $1.2 million and $2.1 million, respectively.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other

In November 2008, we discontinued a plan that was designed to fund post-employment benefits to a limited group of key non-executive employees through whole life insurance policies, while providing life insurance coverage for the participants during the participation period. The cash surrender value of the cancelled whole life insurance policies distributed to the participants in January 2009 was $0.2 million.

(16) Commitments and Contingencies

As described in Notes 1 and 3, on May 1, 2009, we and certain of our subsidiaries filed the Chapter 11 Cases.

We have operating leases for office space and equipment, which expire on various dates through 2016. In addition, we have an agreement to purchase seismic-related services which expires in 2009.

Future minimum commitments as of December 31, 2008 under these operating obligations are as follows (in thousands):

2009	$ 2,189
2010	1,680
2011	1,692
2012	1,704
2013	1,715
Thereafter	4,099
	$ 13,079

Expense relating to operating obligations for the years ended December 31, 2008, 2007 and 2006 was $5.4 million, $7.9 million and $9.6 million, respectively.

We maintain deposits in a trust for future abandonment costs at our East Bay property. The trust was originally funded with $15 million and, with accumulated interest, has 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 property. We have made draws to date of $3.4 million, all of which were made in 2009. Amounts on deposit in the trust account are reflected in other assets. See Note 3 Subsequent Events, Liquidity and Capital Resources for additional information on commitments and contingencies related to abandonment of our oil and natural gas properties.

We had entered into employment agreements with all of our employees including our senior executives and other key employees. In the event of termination of employment (including a change of control of our company) parties to these agreements were entitled to receive a multiple of their salaries and bonuses (typically one, two or three 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. In the event of a change of control event requiring funding of all such cash payments, we estimated the amount payable in cash under these agreements would be approximately $28.9 million at December 31, 2008. See Note 3 Subsequent Events, Liquidity and Capital Resources Subsequent Events Restructure of Prepetition Employee Arrangements for a description of plans that were restructured subsequent to December 31, 2008.

On February 21, 2008, we entered into a plea agreement with the United States Department of Justice under which we pled guilty on that same date to one strict liability, misdemeanor violation of the River and Harbors Act in the United States District Court for the Eastern Division of Louisiana. The plea concludes the

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

investigation announced in June 2007 into possible environmental violations at our East Bay properties in late 2005 and early 2006. Under the plea agreement, we have paid a fine of $75,000 and have made a community service payment of $25,000 to a Louisiana state agency. As a part of the plea agreement, we were subject to inactive probation for one year. The foregoing actions represent the final resolution of this matter with all federal agencies involved with the investigation.

We generate liabilities related to production that is delivered to us in excess of our interest in certain properties, often referred to as production imbalances. Additionally, we may, from time to time, receive cash in excess of amounts that we estimate are due to us for our interest in production, which amounts may be subject to further review, may require more information to resolve or may be in dispute. During 2008, we reduced revenue by $4.4 million reflecting our estimate of amounts that, based on information available to us, may be subject to claim by one purchaser of our production. At December 31, 2008, this amount is included in accrued expenses.

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. See Note 3 Subsequent Events, Liquidity and Capital Resources for additional information on legal proceedings related to the Chapter 11 Cases.

(17) Interim Financial Information (Unaudited)

The following is a summary of consolidated unaudited interim financial information for the years ended December 31, 2008 and 2007:

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(In thousands, except per share data)			
2008				
Revenues	$ 97,496	$ 125,688	$ 94,672	$ 38,396
Costs and expenses	73,863	71,466	57,738	182,964
Business interruption recovery				4,248
Income (loss) from operations	23,633	54,222	36,934	(140,320)
Net income (loss)	2,315	3,996	34,445	(92,968)
Earnings (loss) per share:				
Basic	$ 0.07	$ 0.13	$ 1.07	$ (2.90)
Diluted	0.07	0.12	1.07	(2.90)
2007				
Revenues	$ 108,463	$ 121,666	$ 110,438	$ 114,082
Costs and expenses	105,210	109,252	103,542	201,742
Business interruption recovery	9,084			
Income (loss) from operations	12,337	12,414	6,896	(87,660)
Net income (loss)	3,696	(6,270)	(3,963)	(73,418)
Earnings (loss) per share:				
Basic	$ 0.09	$ (0.18)	$ (0.12)	$ (2.31)
Diluted	0.09	(0.18)	(0.12)	(2.31)

(18) Supplemental Condensed Consolidating Financial Information

In connection with the Senior Unsecured Notes offering, discussed above, all of our current active subsidiaries (the Guarantor Subsidiaries) jointly, severally and unconditionally guaranteed the payment obligations under the Senior Unsecured Notes. The following supplemental financial information sets forth, on a

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. 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.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Supplemental Condensed Consolidating Balance Sheet

As of December 31, 2008

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
ASSETS				
Current assets:				
Cash and cash equivalents	$ 1,991	$	$	$ 1,991
Accounts receivable	37,665	1,244		38,909
Other current assets	4,459	63		4,522
Total current assets	44,115	1,307		45,422
Property and equipment	1,376,387	270,418		1,646,805
Less accumulated depreciation, depletion and amortization	(818,234)	(140,204)		(958,438)
Net property and equipment	558,153	130,214		688,367
Investment in affiliates	84,697	(66)	(84,631)	
Notes receivable, long-term		120,431	(120,431)	
Other assets	32,887	90		32,977
	719,852	251,976	(205,062)	766,766
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities:				
Accounts payable and accrued expenses	$ 114,510	$ 7,161	$	$ 121,671
Deferred tax liability	1,580			1,580
Fair value of commodity derivative instruments	28			28
Current maturities of long-term debt	497,501			497,501
Total current liabilities	613,619	7,161		620,780
Long-term debt		120,431	(120,431)	
Other liabilities	49,114	39,753		88,867
	662,733	167,345	(120,431)	709,647
Stockholders equity:				
Preferred stock		3	(3)	
Common stock	444	98	(98)	444
Additional paid-in capital	382,232	310	(310)	382,232
Retained earnings	(67,201)	84,220	(84,220)	(67,201)
Treasury stock	(258,356)			(258,356)
Total stockholders equity	57,119	84,631	(84,631)	57,119
	719,852	251,976	(205,062)	766,766

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Supplemental Condensed Consolidating Balance Sheet

As of December 31, 2007

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
ASSETS				
Current assets:				
Cash and cash equivalents	$ 8,864	$	$	$ 8,864
Accounts receivable	(78,119)	125,200		47,081
Other current assets	10,431	132		10,563
Total current assets	(58,824)	125,332		66,508
Property and equipment	1,309,898	237,105		1,547,003
Less accumulated depreciation, depletion and amortization	(704,890)	(119,507)		(824,397)
Net property and equipment	605,008	117,598		722,606
Investment in affiliates	199,964	119	(200,083)	
Notes receivable, long-term		221,909	(221,909)	
Other assets	25,652	90		25,742
	$ 771,800	$ 465,048	$ (421,992)	$ 814,856
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities:				
Accounts payable and accrued expenses	$ 117,709	$ 1,215	$	$ 118,924
Fair value of commodity derivative instruments	9,124			9,124
Current maturities of long-term debt				
Total current liabilities	126,833	1,215		128,048
Long-term debt	484,501	221,909	(221,909)	484,501
Other liabilities	58,496	41,841		100,337
	669,830	264,965	(221,909)	712,886
Stockholders equity:				
Preferred stock		3	(3)	
Common stock	441	98	(98)	441
Additional paid-in capital	374,874	1,606	(1,606)	374,874
Retained earnings	(14,989)	198,376	(198,376)	(14,989)
Treasury stock	(258,356)			(258,356)
Total stockholders equity	101,970	200,083	(200,083)	101,970
	$ 771,800	$ 465,048	$ (421,992)	$ 814,856

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Supplemental Condensed Consolidating Statement of Operations

Year Ended December 31, 2008

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Revenue:				
Oil and natural gas	$ 259,258	$ 96,764	$	$ 356,022
Other	34,289	154	(34,213)	230
	293,547	96,918	(34,213)	356,252
Costs and expenses:				
Lease operating expenses	42,587	22,946		65,533
Taxes, other than on earnings	775	10,470		11,245
Exploration expenditures, dry hole cost and impairments	134,705	5,897		140,602
Depreciation, depletion, amortization and accretion	85,595	22,093		107,688
General and administrative	42,416	16,290	(15,000)	43,706
Other expenses	17,248	9		17,257
Total costs and expenses	323,326	77,705	(15,000)	386,031
Business interruption recovery	4,248			4,248
Income (loss) from operations	(25,531)	19,213	(19,213)	(25,531)
Other income (expense):				
Interest expense, net	(45,749)			(45,749)
Gain (loss) on derivative instruments	2,053			2,053
Income (loss) before income taxes	(69,227)	19,213	(19,213)	(69,227)
Income taxes	17,015			17,015
Net income (loss)	$ (52,212)	$ 19,213	$ (19,213)	$ (52,212)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Supplemental Condensed Consolidating Statement of Operations

Year Ended December 31, 2007

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Revenue:				
Oil and natural gas	$ 365,707	$ 88,633	$	$ 454,340
Other	58,595	172	(58,458)	309
	424,302	88,805	(58,458)	454,649
Costs and expenses:				
Lease operating expenses	95,237	(22,877)		72,360
Taxes, other than on earnings	364	9,536		9,900
Exploration expenditures, dry hole cost and impairments	193,560	19,562		213,122
Depreciation, depletion, amortization and accretion	150,130	24,411		174,541
General and administrative	60,421	16,303	(15,000)	61,724
Other expenses	(10,313)	(1,588)		(11,901)
Total costs and expenses	489,399	45,347	(15,000)	519,746
Business interruption recovery	9,084			9,084
Income (loss) from operations	(56,013)	43,458	(43,458)	(56,013)
Other income (expense):				
Interest expense, net	(44,628)			(44,628)
Gain (loss) on derivative instruments	(13,083)			(13,083)
Loss on early extinguishment of debt	(10,838)			(10,838)
Income (loss) before income taxes	(124,562)	43,458	(43,458)	(124,562)
Income taxes	44,607			44,607
Net income (loss)	$ (79,955)	$ 43,458	$ (43,458)	$ (79,955)

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Supplemental Condensed Consolidating Statement of Operations

Year Ended December 31, 2006

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Revenue:				
Oil and gas	$ 303,425	$ 145,761	$	$ 449,186
Other	(54,711)	202	54,873	364
	248,714	145,963	54,873	449,550
Costs and expenses:				
Lease operating expenses	6,431	54,405		60,836
Taxes, other than on earnings	1,739	11,893		13,632
Exploration expenditures, dry hole cost and impairments	82,511	53,914		136,425
Depreciation, depletion, amortization and accretion	123,141	79,593		202,734
General and administrative	119,083	16,030	(15,000)	120,113
Other expenses	4,022			4,022
Total costs and expenses	336,927	215,835	(15,000)	537,762
Business interruption recovery	32,869			32,869
Income (loss) from operations	(55,344)	(69,872)	69,873	(55,343)
Interest expense, net	(23,141)	(1)		(23,142)
Income (loss) before income taxes	(78,485)	(69,873)	69,873	(78,485)
Income taxes	28,085			28,085
Net income (loss)	$ (50,400)	$ (69,873)	$ 69,873	$ (50,400)

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Supplemental Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2008

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Net cash provided by operating activities	$ 154,340	$ 30,270	$	$ 184,610
Cash flows used in investing activities:				
Property acquisitions	(20,833)	(92)		(20,925)
Exploration and development expenditures	(168,979)	(30,178)		(199,157)
Other property and equipment additions	(724)			(724)
Proceeds from the sale of oil and natural gas assets	15,576			15,576
Net cash used in investing activities	(174,960)	(30,270)		(205,230)
Cash flows provided by (used in) financing activities:				
Deferred financing costs	(5)			(5)
Repayments of long-term debt	(120,000)			(120,000)
Proceeds from long-term debt	133,000			133,000
Exercise of stock options and warrants	752			752
Net cash provided by financing activities	13,747			13,747
Net decrease in cash and cash equivalents	(6,873)			(6,873)
Cash and cash equivalents at the beginning of the period	8,864			8,864
Cash and cash equivalents at the end of the period	$ 1,991	$	$	$ 1,991

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Supplemental Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2007

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Net cash provided by operating activities	$ 272,356	$ 21,533	$	$ 293,889
Cash flows used in investing activities:				
Insurance recoveries	19,574			19,574
Property acquisitions	(6,922)	(424)		(7,346)
Exploration and development expenditures	(302,737)	(21,109)		(323,846)
Other property and equipment additions	(1,402)			(1,402)
Proceeds from the sale of oil and natural gas assets	68,599			68,599
Net cash used in investing activities	(222,888)	(21,533)		(244,421)
Cash flows provided by (used in) financing activities:				
Deferred financing costs	(11,178)			(11,178)
Repayments of long-term debt	(530,499)			(530,499)
Proceeds from public offering net of commissions	698,000			698,000
Purchase of shares into equity	(200,916)			(200,916)
Exercise of stock options and warrants	775			775
Net cash provided by (used in) financing activities	(43,818)			(43,818)
Net decrease in cash and cash equivalents	5,650			5,650
Cash and cash equivalents at the beginning of the period	3,214			3,214
Cash and cash equivalents at the end of the period	$ 8,864	$	$	$ 8,864

96

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Supplemental Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2006

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Net cash provided by operating activities	$ 225,000	$ 47,074	$	$ 272,074
Cash flows used in investing activities:				
Acquisition of business, net of cash acquired	(420)			(420)
Property acquisitions	(15,897)			(15,897)
Exploration and development expenditures	(294,971)	(46,965)		(341,936)
Other property and equipment additions	(527)			(527)
Net cash used in investing activities	(311,815)	(46,965)		(358,780)
Cash flows provided by (used in) financing activities:				
Deferred financing costs	(853)			(853)
Repayments of long-term debt	(73,000)	(109)		(73,109)
Proceeds from public offering net of commissions	155,000			155,000
Exercise of stock options and warrants	2,093			2,093
Net cash provided by (used in) financing activities	83,240	(109)		83,131
Net decrease in cash and cash equivalents	(3,575)			(3,575)
Cash and cash equivalents at the beginning of the period	6,789			6,789
Cash and cash equivalents at the end of the period	$ 3,214	$	$	$ 3,214

(19) New Accounting Pronouncements

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, Fair Value Measurements, which establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for financial statements issued for periods beginning after November 15, 2007. In February 2008, the FASB issued FASB Staff Position (FSP) FAS 157-2, which defers the effective date of SFAS No. 157 for non-financial assets and liabilities that are not recorded at fair value on a recurring basis until periods beginning after November 15, 2008. We adopted the non-deferred portion of SFAS No. 157 on January 1, 2008 on a prospective basis. In October 2008, the FASB issued FSP FAS 157-3, which became effective immediately and clarified the application of SFAS No. 157 in a market that is not active. The adoption of SFAS No. 157 and FSP FAS 157-3 has not had a material impact on our financial statements.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Liabilities, which permits entities to choose to measure individually selected financial instruments at fair value. SFAS No. 159 is effective for financial statements issued for periods beginning after November 15, 2007. Since we did not elect the fair value option on any qualifying financial instruments at any time during 2008, this statement has had no impact on our financial statements.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations, which provides new accounting guidance and disclosure requirements for business combinations and is effective for business combinations which occur starting with the first fiscal year beginning on or after December 15, 2008.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements. This statement provides new accounting guidance and disclosure and presentation requirements for noncontrolling interests in an entity. SFAS No. 160 is effective for the first fiscal year beginning on or after December 15, 2008. We do not expect the effect of this statement on our financial statements to be material.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities-an amendment of FASB Statement No. 133, which provides new disclosure requirements for an entity s derivative and hedging activities. SFAS No. 161 is effective for periods beginning after November 15, 2008. We do not expect the effect of this statement on our financial statements to be material.

In June 2008, the FASB issued FSP Emerging Issues Task Force (EITF) Issue No. 03-6-1. This FSP concluded that instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, should be included in the earnings allocations in computing basic earnings per share under the two-class method. This FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008 with prior period retrospective application. We do not expect the effect of this FSP on our financial statements to be material.

In December 2008, the FASB issued FSP SFAS No. 132(R)-1. This FSP requires companies to enhance disclosures related to the assets held in defined benefit plans and other post-retirement benefits. This FSP is effective for financial statements issued for fiscal years ending after December 15, 2009. We do not expect this FSP to have any impact on our financial statements.

In December 2008, the SEC issued a final rule, Modernization of Oil and Gas Reporting, which amends its oil and gas reserves estimation and disclosure requirements. The new requirements, among other things: permits the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes; modifies the prices used to estimate reserves for SEC disclosure purposes to an average price based upon the prior twelve month period rather than a year-end price; allows the optional disclosure of probable and possible reserves to investors; and requires 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 is effective January 1, 2010 for reporting 2009 annual oil and natural gas reserve information. We will adopt the provisions of the final rule in connection with the filing of our Annual Report on Form 10-K for the fiscal year ending December 31, 2009. We are currently evaluating the impact of the final rule.

In May 2009, the FASB issued SFAS No. 165, Subsequent Events, which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. In particular, SFAS No. 165 sets forth:

- the period after the balance sheet date during which management should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements;

- the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and

- disclosures that an entity should make about events or transactions that occurred after the balance sheet date.

SFAS No. 165 is effective for interim or annual financial periods ending after June 15, 2009. We are currently assessing what impact SFAS 165 may have on our financial position, results of operations or cash flows.

In June 2009, the FASB issued SFAS No. 166, Accounting for Transfers of Financial Assets-an amendment of FASB Statement No. 140, which provides accounting and disclosure guidance regarding transfers of financial assets. SFAS No. 166 is effective for periods beginning after November 15, 2009. We do not expect the effect of this statement on our financial statements to be material.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In June 2009, the FASB issued SFAS No. 167, Amendments to FASB Interpretation No. 46(R), to improve financial reporting by enterprises involved with variable interest entities. SFAS No. 167 is effective for periods beginning after November 15, 2009. We do not expect the effect of this statement on our financial statements to be material.

In July 2009, the FASB issued SFAS No. 168, The FASB Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles a replacement of FASB Statement No. 162. The FASB Accounting Standards Codification™ (Codification) will become the source of authoritative U.S. generally accepted accounting principles (GAAP) recognized by the FASB to be applied by nongovernmental entities. On the effective date of this statement, the Codification will supersede all then-existing non-SEC accounting and reporting standards. All other nongrandfathered, non-SEC accounting literature not included in the Codification will become nonauthoritative. While the Codification does not change GAAP, it introduces a new structure that reorganizes the thousands of GAAP pronouncements into roughly 90 accounting topics, which are accessible in an online research system. SFAS No. 168 is effective for financial statements issued for interim and annual periods ending after September 15, 2009. In November 2008, SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles, became effective, which identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements that are presented in conformity with GAAP. Once the Codification is in effect, all of its content will carry the same level of authority, effectively superseding SFAS No. 162.

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

Our estimates of proved reserves are based on reserve reports prepared by Netherland, Sewell & Associates, Inc. and Ryder Scott Company, L.P., independent petroleum engineers as of December 31, 2008. 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth our net proved reserves, including the changes therein, and proved-developed reserves:

	Crude Oil (Mbbls)	Natural Gas (Mmcf)	Barrels of Oil Equivalent (Mboe)
Proved-developed and undeveloped reserves:			
December 31, 2005	31,478	166,949	59,303
Sales of reserves in place	(129)	(750)	(254)
Extensions, discoveries and other additions (a)	1,057	44,336	8,446
Revisions	515	(1,704)	231
Production	(3,007)	(38,708)	(9,458)
December 31, 2006	29,914	170,123	58,268
Sales of reserves in place (b)	(363)	(10,214)	(2,066)
Purchases of reserves in place (c)	46	3,628	651
Extensions, discoveries and other additions (d)	469	12,361	2,529
Revisions (e)	1,258	(39,139)	(5,265)
Production	(3,201)	(33,641)	(8,808)
December 31, 2007	28,123	103,118	45,309
Sales of reserves in place	(265)	(1,819)	(568)
Extensions, discoveries and other additions (f)	956	8,482	2,370
Revisions (g)	(5,125)	(2,477)	(5,538)
Production	(2,052)	(16,496)	(4,802)
December 31, 2008	21,637	90,808	36,771
Proved-developed reserves:			
December 31, 2006	24,811	117,392	44,376
December 31, 2007	23,636	85,926	37,957
December 31, 2008	17,052	79,413	30,288

(a) Includes approximately 2.2 MMboe associated with discoveries in Greater Bay Marchand.

(b) Includes the sale of approximately 2.1 Mmboe proved reserves in the sale of substantially all of our onshore South Louisiana producing assets.

(c) Purchases are the result of the acquisition of an additional interest in our deepwater leases and reserves acquired through the non participation rights in a well operation.

(d) Includes approximately 1.8 Mmboe associated with discoveries in Greater Bay Marchand.

(e) Comprised of approximately 1.4 Mmboe of positive revisions and approximately 6.6 Mmboe of negative revisions, of which approximately 4.1 Mmboe was on fields that were impaired during 2007.

(f) Includes approximately 1.2 Mmboe associated with discoveries in Greater Bay Marchand and approximately 0.4 Mmboe associated with discoveries at our East Bay field.

(g) Comprised of approximately 3.5 Mmboe of negative revisions associated with price decreases in both oil and natural gas and approximately 2.0 Mmboe of negative revisions associated with underperformance of wells.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	2008	2007
	(In thousands)	
Proved properties	$ 1,601,748	$ 1,496,068
Unproved properties	36,274	42,083
Accumulated depreciation, depletion and amortization	(951,316)	(817,923)
Net capitalized costs	$ 686,706	$ 720,228

Costs incurred for oil and natural gas property acquisition, exploration and development activities for the years ended December 31, 2008, 2007 and 2006 are as follows:

	Years Ended December 31,		
	2008	2007	2006
	(In thousands)		
Acquisitions			
-Proved	$	$ 2,167	$ 420
-Unproved	20,925	7,346	15,896
Exploration	56,202	191,621	224,147
Development (1)	127,948	121,769	167,346
Costs incurred	$ 205,075	$ 322,903	$ 407,809

(1) Includes asset retirement obligations incurred of $13.4 million, $5.6 million and $8.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.

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 SFAS No. 69, Disclosures about Oil and Gas Producing Activities . 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 will probably differ from those required to be used in these calculations; (2) due to future market conditions and governmental regulations, actual rates of production achieved in future years may vary significantly from the rate of production assumed in the calculations; (3) selection of a 10% discount rate 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.

Under the Standardized Measure, future cash inflows were estimated by applying the use of physical pricing determined by the market on the last day of the fiscal year, 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 market price on the last day of the fiscal year are determined by comparing our historical realized price experience with the comparable

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

historical market, or posted, price. These adjustments can vary significantly over time both in amount and as a percentage of the market price on the last day of the fiscal year, especially related to oil prices during periods when the market price for oil varies widely or the year end market price is significantly higher or lower than the average realized price during the year. The price adjustments reflected in our year end 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 flow 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 is required by Statement 69.

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

	2008	2007	2006
		(In thousands)	
Future cash inflows	$ 1,517,701	$ 3,384,268	$ 2,688,624
Future production costs	(612,934)	(895,352)	(700,915)
Future development costs	(347,107)	(316,753)	(355,238)
Future income tax expense	(15,176)	(598,874)	(415,250)
Future net cash flows after income taxes	542,484	1,573,289	1,217,221
10% annual discount for estimated timing of cash flows	(126,313)	(480,354)	(323,747)
Standardized measure of discounted future net cash flows	$ 416,171	$ 1,092,935	$ 893,474

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, 2008, 2007 and 2006 is as follows:

	2008	2007	2006
		(In thousands)	
Beginning of the period	$ 1,092,935	$ 893,474	$ 1,261,246
Sales and transfers of oil and natural gas produced, net of production costs	(277,493)	(375,060)	(379,624)
Net changes in prices and production costs	(749,426)	788,913	(648,509)
Extensions, discoveries and improved recoveries, net of future production costs	28,437	106,690	250,255
Revision of quantity estimates	(117,355)	(210,230)	8,316
Previously estimated development costs incurred during the period	27,932	63,588	97,073
Purchase and sales of reserves in place, net	(21,514)	(50,060)	(5,951)
Changes in estimated future development costs	(46,956)	(8,935)	(28,356)
Changes in production rates (timing) and other	(35,692)	(151,746)	(91,709)
Accretion of discount	147,029	118,830	180,618
Net change in income taxes	368,274	(82,529)	250,115
Net increase (decrease)	(676,764)	199,461	(367,772)
End of period	$ 416,171	$ 1,092,935	$ 893,474

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At December 31, 2008, 2007 and 2006, 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 period-end prices:

	2008	2007	2006
per Mcf for natural gas	$ 6.05	$ 6.98	$ 5.54
per barrel for oil	$ 44.77	$ 94.76	$ 58.40

(21) Related Party Transactions

One of our former directors was a senior managing director of Evercore Group L.L.C. (Evercore). Evercore provided financial advisory services to us in connection with the Stone transaction, the Woodside offer and our exploration of strategic alternatives. Evercore received fees of $1.6 million in 2006 in connection with the financial advisory services related to the Stone transaction and the consideration of the unsolicited offer from Woodside. In addition, a $7.0 million fee was due to Evercore upon the earlier of the consummation of a transaction or September 5, 2007, of which $2.3 million was accrued during 2006 and the remaining $4.7 million was accrued during the first nine months of 2007 and paid in September 2007.

Table of Contents

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

None.

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 not effective as of December 31, 2008 because of the material weaknesses discussed in Item 9A(b) below.

(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. Our internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of management and our directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the consolidated financial statements.

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, 2008 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). Management s evaluation included an assessment of the design of our internal control over financial reporting and testing of the operating effectiveness of our internal control over financial reporting. During this evaluation, management identified the following material weaknesses in our internal control over financial reporting and has concluded that as a result of these material weaknesses, our internal control over financial reporting was not effective as of December 31, 2008 based upon the criteria issued by COSO:

Control Environment over Financial Reporting. We 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.

These deficiencies contributed to the development of the *Complex and Non-Routine Accounting Matters* and *Period-End Financial Reporting Process* material weaknesses described below.

Complex or Non-Routine Accounting Matters. We lacked sufficient expertise and resources within our 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.

Table of Contents

Period-End Financial Reporting Process. We also lacked sufficient expertise and resources within our 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.

There were material errors in AROs and impairments resulting from the material weaknesses and the errors were corrected prior to the issuance of the financial statements.

KPMG LLP, an independent registered public accounting firm, has issued a report concerning the effectiveness of our internal control over financial reporting as of December 31, 2008. 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 system of internal control over financial reporting during the three months ended December 31, 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting, except as described below.

During 2008, we experienced changes in personnel, including our Controller, who were performing key quarterly and annual internal control processes. The material weaknesses in our internal control over financial reporting as described above occurred during the three months ended December 31, 2008.

In light of the material weaknesses described above, we performed additional procedures that were designed to provide reasonable assurance regarding the reliability of (1) our financial reporting; and (2) the preparation of the consolidated financial statements contained in this Annual Report. Accordingly, management believes that the consolidated financial statements included in this Annual Report fairly present, in all material respects, our financial position, results of operations and cash flows for the periods presented.

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. Accordingly, even effective internal control over financial reporting can only provide reasonable assurance of achieving their control objectives.

(d) Management s Remediation Plans

We plan to remediate our material weaknesses caused by a lack of personnel when we are able to recruit and retain the required resources. Management believes that (1) hiring adequate accounting resources with appropriate accounting expertise and (2) enhancing policies and procedures will remedy the material weaknesses described above.

We are committed to finalizing our remediation action plan and implementing the necessary enhancements to our resources, policies and procedures to fully remediate the material weaknesses discussed above, and these material weaknesses will not be considered remediated until (1) new resources are fully engaged and new processes are fully implemented, (2) new processes are implemented for a sufficient period of time and (3) we are confident that the new processes are operating effectively.

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

None.

PART III

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

Directors and Executive Officers

Set forth below are the names, ages and positions of our current directors and executive officers:

Name	Age	Positions Held
Jerry D. Carlisle	63	Director
Robert D. Gershen	55	Director
James R. Latimer, III	63	Director
Bryant H. Patton	50	Director
Steven J. Pully	49	Director
Alan D. Bell	63	Chief Restructuring Officer
Thomas D. DeBrock	49	Senior Vice President of Exploration
Stephen D. Longon	51	Executive Vice President and Chief Operating Officer
John H. Peper	57	Executive Vice President, General Counsel and Corporate Secretary
Tiffany J. Thom	37	Vice President, Treasurer and Investor Relations
L. Keith Vincent	54	Senior Vice President of Acquisitions and Land

Jerry D. Carlisle has been a director since March 2003. Mr. Carlisle was Deputy Inspector General, Audit and Review, in the office of inspector general in the City of New Orleans from December 2008 to April 2009. Mr. Carlisle has been vice president and director of DarC Marketing, Inc., a family-owned marketing company, since 1997. From 1983 to 1997, Mr. Carlisle was vice president, controller and chief accounting officer of The Louisiana Land and Exploration Company (LL&E) and, from 1979 to 1983, he held various management positions at LL&E. Mr. Carlisle has a masters of business administration from Loyola University, is a certified public accountant, and serves as a trustee of the Mississippi State University Business School. Mr. Carlisle is also a director of Louisiana Citizen s Property Insurance Corporation.

Robert D. Gershen has been a director since May 1998. Since September 1989, Mr. Gershen has been president of Associated Energy Managers, LLC, an investment management firm specializing in private equity investments in the energy sector. In addition, since December 2001, Mr. Gershen has served as president of Longview Energy Company, a privately held oil and gas company.

James R. Latimer, III has been a director since May 2008. Since 1991, Mr. Latimer has been the head of The Latimer Companies, a private oil and gas exploration and development company. He is also a partner of Blackhill Partners/Blackhill Advisors, a financial advisory and merchant banking firm, primarily in energy and technology industries, which he founded in 2000. Mr. Latimer currently serves as a director of NGP Capital Resources Company.

Bryant H. Patton has been a director since May 2008. Mr. Patton is the president of BRYCAP Investments, Inc., a merchant banking firm specializing in energy related companies that he founded in 1989. In 2000, he also co-founded Camden Resources, Inc., a private oil and gas exploration and production company, and served as executive vice president until the company was acquired at the end of 2007. Mr. Patton also served as senior vice president of Associated Energy Managers, LLC, an investment management firm specializing in private equity investments in the energy sector, from 1991 to 1998. Mr. Patton also is a director of the general partner of Abraxas Energy Partners, L.P.

Steven J. Pully has been a director since May 2008. Mr. Pully has been the General Counsel of Carlson Capital, L.P., a multi-strategy investment firm, since July 2008. From October 2007 to April 2008, he was a consultant in the asset management industry and provided consulting services for Carlson Capital, L.P. From December 2001 to October 2007, Mr. Pully worked for Newcastle Capital Management, L.P., an investment partnership, where he served as president from January 2003 through October 2007. He served as chief executive officer of New Century Equity Holdings Corp., from June 2004 through October 2007. Prior to joining Newcastle Capital Management, he was an investment banker at Banc of America Securities, Inc. and Bear Stearns with a primary focus on the energy sector. Mr. Pully is also a director of Cano Petroleum, Inc. and Ember Resources Inc. Mr. Pully is licensed to practice law in the State of Texas and is a CPA and CFA.

Alan D. Bell joined us in March 2009 as our chief restructuring officer. Mr. Bell has extensive experience in the petroleum industry. Mr. Bell started his career as a production engineer from 1969 to 1972 for Chevron Oil Company in the Gulf of Mexico. He then spent 33 years with Ernst & Young auditing natural resource companies, dealing with the Securities and Exchange Commission and working with senior executives and boards of directors of public companies within the energy industry. At the time of his retirement in June 2006, Mr. Bell was the director of Ernst & Young LLP s energy practice in the Southwest U.S. area. Mr. Bell earned a master s degree in business from Tulane University and a bachelor s degree in petroleum engineering from the Colorado School of Mines, and is a certified public accountant licensed in Texas. Mr. Bell is also a director of Dune Energy, Inc. where he serves as the Chairman of the Audit Committee. Until June 4, 2009, Mr. Bell served as a director of Toreador Resources Corporation.

Thomas D. DeBrock joined us in June 1998 as a senior geologist and was promoted to exploration manager, New Orleans in September 2004, vice president of exploration in August 2006 and senior vice president of exploration in August 2007. He has 23 years of energy industry experience in both the exploration and development efforts. Mr. DeBrock began his career with GTS Seismic Corporation, and then joined Odeco Oil and Gas working the Gulf of Mexico Shelf followed by a move to LL&E to work the Onshore area of South Louisiana. After the merger of LL&E with Burlington Resources, he joined W&T Offshore before joining us.

Stephen D. Longon joined us in July 2007 as senior vice president drilling and engineering and in February 2008 was assigned additional responsibilities and was named senior vice president drilling, engineering and production. In July 2008, Mr. Longon was named executive vice president and chief operating officer. He has 29 years of energy industry experience. He was most recently with Dominion Exploration & Production, Inc. (Dominion), from May 2001 to July 2007 in its New Orleans office serving as general manager of production and operations, with responsibility for their operations on the Gulf of Mexico Shelf, in the deepwater Gulf of Mexico and onshore South Louisiana. During his earlier years with Dominion, he played a key role in the integration and management of substantial resource assets in the Arklatex area, South Texas and the Texas Gulf Coast. Prior to his position with Dominion, Mr. Longon served in a variety of Gulf of Mexico operational roles as production manager with ATP Oil & Gas Corp. from September 2000 to May 2001, various management positions over construction, Gulf of Mexico assets and deepwater development for Vastar Resources, Inc. from October 1993 to September 2000 and for Atlantic Richfield Company in positions of increasing responsibility, primarily in the Gulf of Mexico and onshore Texas and south Louisiana from June 1979 to October 1993.

John H. Peper joined us in January 2002 as executive vice president, general counsel and corporate secretary. Prior to joining us, Mr. Peper was senior vice president, general counsel and secretary of Hall Houston Oil Company (HHOC) since February 1993. Mr. Peper also served as a director of HHOC from October 1991 until we acquired HHOC in January 2002. For more than five years prior to joining HHOC, Mr. Peper was a partner in the law firm of Jackson Walker, L.L.P., where he continued to serve in an of counsel capacity through 2001.

Tiffany J. Thom joined us as a senior asset management engineer in 2000, and has since held the positions of director of corporate reserves and director of investor relations. In July 2009, she was designated as our principal financial officer. Prior to joining us, Ms. Thom was a senior reservoir engineer with Exxon Production Company and ExxonMobil Company. Ms. Thom holds a B.S. in Engineering from the University of Illinois and a M.B.A. in Management with a concentration in Finance from Tulane University.

L. Keith Vincent joined us as land manager in January 1999 and was appointed vice president, land and business development in July 2000. In August 2007, he was promoted to senior vice president land and business development and in February 2008 was assigned additional responsibilities and was appointed senior vice president of acquisitions and land. Mr. Vincent was vice president, land and legal, of Great River Oil & Gas Corporation from 1994 to October 1998. From October 1998 until joining us, Mr. Vincent was a self-employed sole proprietor performing contract work for various oil and gas exploration companies. During Mr. Vincent s 29-year career, he also held various managerial positions with Davis Petroleum Corporation and Transco Exploration Company.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our directors, executive officers and persons who beneficially own more than 10% of our outstanding common stock to file initial reports of ownership and changes in ownership of common stock with the SEC. Reporting persons are required by the SEC to furnish us with copies of all Section 16(a) forms they file. Based solely on our review of the copies of reports we received and written representations from our directors and officers, we believe that all filings required to be made under Section 16(a) for the fiscal year ended December 31, 2008 were timely made with the exception of the following:

- On April 3, 2008, Dina B. Riviere filed a Form 4 due March 18, 2008;
- On April 3, 2008, Dina B. Riviere filed a Form 4 due March 19, 2008;
- On June 2, 2008, Dina B. Riviere filed a Form 4 due April 24, 2008; and
- On October 23, 2008, Harold D. Carter filed a Form 4 due October 8, 2008.

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 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.

Nominating Procedures

When seeking candidates for director, the Nominating & Governance Committee may solicit suggestions from incumbent directors, management, stockholders or others. In addition, the Nominating & Governance Committee has authority under its charter to retain a search firm for this purpose. After conducting an initial evaluation of a potential candidate, the Nominating & Governance Committee will interview that candidate if it believes such candidate might be suitable to be a director. The Nominating & Governance Committee may also ask the candidate to meet with management. If the Nominating & Governance Committee believes a candidate would be a valuable addition to the Board, it will recommend to the full Board that candidate s election.

The Nominating & Governance Committee selects each nominee based on the nominee s skills, achievements and experience. The Nominating & Governance Committee considers a variety of factors in selecting candidates, including, but not limited to the following: independence, wisdom, integrity, an understanding and general acceptance of our corporate philosophy, valid business or professional knowledge and experience, a proven record of accomplishment with excellent organizations, an inquiring mind, a willingness to speak one s mind, an ability to challenge and stimulate management and a willingness to commit time and energy.

Table of Contents

Audit Committee Information

The Board has a standing Audit Committee established in accordance with Section (3)(a)(58)(A) of the Exchange Act, the current members of which are Messrs. Carlisle, Latimer and Pully. The Board, in its business judgment, has determined that each of the members of the Audit Committee is independent as defined by the Company s categorical standards on independence as well as the listing standards of the NYSE and the rules of the SEC applicable to audit committee members. Further, the Board, in its business judgment, has determined that Mr. Carlisle qualifies as an audit committee financial expert as described in Item 407(d)(5) of Regulation S-K.

Item 11. ***Executive Compensation***

Compensation Committee Interlocks and Insider Participation

No member of the Compensation Committee is now, or at any time has been, employed by or served as an officer of our company or any of its subsidiaries or had any substantial business dealings with our company or any of its subsidiaries. None of our executive officers are now, or at any time has been, a member of the compensation committee or board of directors of another entity, one of whose executive officers has been a member of the Compensation Committee or the Board of our company.

Compensation Committee Report

The Compensation Committee has reviewed and discussed the disclosure set forth below under the heading Compensation Discussion and Analysis with management and, based on the review and discussions, it has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the fiscal year ended December 31, 2008.

Respectfully submitted by the Compensation Committee,

Robert D. Gershen
James R. Latimer, III*
Steven J. Pully*

* Messrs. Latimer and Pully joined the Compensation Committee in May 2008 and February 2009, respectively.

Compensation Discussion and Analysis

Objectives of Our Executive Compensation Program

The Compensation Committee (for purposes of this Item 11, the Committee) believes that our executive compensation program should motivate management to achieve our annual, long-term and strategic goals, and enhance stockholder value. Our compensation objectives are to attract and retain the best available talent and foster a corporate culture of teamwork to achieve our business objectives while rewarding individual contributions, all in order to achieve a superior rate of stockholder return over time.

The Committee based its decisions with respect to performance-measured compensation of our executive officers for services rendered in fiscal 2008 upon these principles and its assessment of each officer s potential to enhance long-term stockholder value. The Committee also considered each executive officer s current salary and prior year compensation, as well as compensation paid to the executive officer s peers when making its compensation decisions.

Table of Contents

Setting Our Executive Officer Compensation

Role of the Compensation Consultant, the Committee and Management

The Committee has engaged Towers Perrin and Frederic W. Cook & Co., Inc. in the past as consultants to assist it in determining appropriate types and levels of compensation. For the fiscal year 2008, Towers Perrin assisted the Committee with an evaluation of the base salary levels of our top executive officers. Frederic W. Cook & Co., Inc. prepared an analysis of the following compensation matters for each of the officers named in the Summary Compensation Table located in our proxy statement for the 2008 Annual Meeting of Stockholders: (1) base salary levels, (2) actual total cash compensation (comprised of base salary and cash incentive bonus), (3) total long term incentive compensation and (4) actual total direct compensation. The Committee s use of this analysis is discussed in more detail below. In addition, Frederic W. Cook & Co., Inc. prepared an analysis of director compensation for the Committee as discussed in more detail below under Director Compensation General. Neither firm performs services for us other than its work for the Committee.

Prior to July 2008, decisions with respect to the compensation of our executive officers (other than our Chief Executive Officer) were made by the Committee based on recommendations by the Chief Executive Officer. Subsequent to July 2008, decisions with respect to the compensation of our executive officers (with the exception of our Chief Executive Officer) were made by the Board based on recommendations by the Committee. The Committee expects recommendations from our Chief Executive Officer but exercises its own judgment and makes its own determination. The compensation of our Chief Executive Officer is recommended by the Committee and approved by the independent members of the Board. The compensation of our non-executive officers and other employees is determined by our executive officers.

Determining Compensation

The Committee, which relies upon the judgment of its members in making compensation decisions, has established a number of processes to assist it in ensuring that our executive compensation program supports our objectives and company culture. Among those processes are competitive benchmarking and an assessment of individual and company performance, which are described in more detail below.

Competitive Benchmarking. The Committee compares our executive pay practices against other companies to assist it in the review and comparison of each element of compensation for our executive officers. This practice recognizes that (1) our compensation practices must be competitive in the marketplace and (2) marketplace information is one of the many factors considered in assessing the reasonableness of our executive compensation program. The Committee s use of competitive benchmarking for each element of compensation is discussed in more detail below. The peer group used by the Committee for its fiscal 2008 compensation decisions included: ATP Oil & Gas Corp., Bois d Arc Energy, Inc., Callon Petroleum Company, Mariner Energy, Inc., McMoRan Exploration Co., Meridian Resource Corp., Stone Energy Corp. and W & T Offshore, Inc. (collectively, the 2008 Peer Group). The 2008 Peer Group was formulated by management and approved by the Committee. This is the same peer group used for comparing our stock performance as set forth under Part II, Item 5, Market for Registrant s Common Stock, Related Stockholder Matters and Issuer Purchases of Equity Securities with the exception of Bois d Arc Energy, Inc., which was not included for stock performance comparisons due to its acquisition by Stone in 2008.

Assessment of Individual and Company Performance. The Committee believes that a balance of individual and company performance criteria should be used in establishing total compensation. Individual and company performance determines the amounts earned under our annual cash incentive bonus program. Company performance is a significant factor in the value of equity-based compensation. These performance measures are discussed in more detail below.

Table of Contents

Types of Compensation

We generally provide three primary types of compensation to our executive officers:

- annual base salary;
- annual cash incentive bonus; and
- long-term equity-based compensation, consisting of restricted share units (settled in shares or cash) and stock options and share appreciation rights (settled in shares or cash), the value of which is directly linked to the value of our common stock.

Occasionally, we provide one-time cash payments to certain executive officers as described in more detail below under Cash Payments.

The distribution of compensation among the various components of compensation is driven by the Committee s belief that a substantial component of each officer s annual compensation is dependent upon measurable improvement to stockholder value and, therefore, at risk. For example, the annual cash incentive bonus is primarily determined by the Committee s assessment of success measured against pre-established corporate goals, which has the effect of making it at risk. No amount of annual incentive is guaranteed. The long-term equity-based compensation, although not directly tied to the corporate goals, is variable because its real value is driven by future stock performance, which is linked to corporate performance.

Annual Base Salary

We provide our executive officers and other employees with an annual base salary to compensate them for services rendered during the year.

At least once each year, the Committee reviews each executive officer s annual base salary. This review is conducted with the assistance of Towers Perrin. Towers Perrin s analysis typically includes (1) an assessment, which is based on market data derived from published surveys, of each executive officer s compensation level compared to other executive officers in similar positions in the exploration and production industry as well as the marketplace, in general, and (2) a detailed review of the compensation paid to other executive officers in similar positions in a selected peer group of companies. In general, the Committee targets the median to 75th percentile of available market data for the base salaries levels of our executive officers. A competitive base salary is consistent with our long-term objectives of attracting and retaining highly qualified, competent executives.

In December 2007, Towers Perrin used the following surveys to gather the market data for the first part of its analysis: (1) The William M. Mercer, *2007 Energy Compensation Survey*, and (2) the Effective Compensation, Incorporated, *2007 Oil & Gas E&P Compensation Survey*. As the second part of its analysis, Towers Perrin reviewed fiscal 2007 compensation disclosures contained in the proxy statements filed by the 2008 Peer Group.

Based on the data provided by Towers Perrin, the Committee approved fiscal 2008 base salary adjustments for each executive officer (other than Mr. Bachmann), consistent with the Committee s compensation philosophy targeting the median to 75th percentile of the 2008 Peer Group. The following table provides the base salaries for our Named Executive Officers in fiscal years 2007 and 2008 and the percentage increase in their 2008 base salary from their 2007 base salary.

Named Executive Officer	**2007 Base Salary ($)**	**2008 Base Salary ($)**	**Percentage Increase (%)**
Richard A. Bachmann	500,000	525,000	5
Joseph T. Leary	250,000	265,000	6
Thomas D. DeBrock	260,000	270,000	4
Stephen D. Longon (1)	240,000	340,000	42
John H. Peper	250,000	275,000	10

Table of Contents

(1) Mr. Longon s salary was increased from $240,000 to $245,000 in December 2007 (representing a 2.08% increase). In July 2008, Mr. Longon s salary was increased by the Committee from $245,000 to $340,000 in connection with his promotion to Executive Vice President and Chief Operating Officer.

Cash Payments

From time to time, we make cash payments to our executive officers pursuant to the terms of agreements with our officers and, less frequently, in special recognition of individual and/or company performance.

Commencing December 1, 2007, Mr. DeBrock was entitled to a payment of $120,000 each December 1 through December 1, 2012. The payment received by Mr. DeBrock in 2008 is reflected in the Bonus column of the Summary Compensation Table below. Please see Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table for additional information regarding this payment.

Annual Cash Incentive Bonus

The purpose of our annual incentive bonus program is to motivate our executive officers to achieve, and reward the accomplishment of, our annual company objectives and individual performance. Incentive bonuses are based on quantitative and qualitative factors that the Committee may deem appropriate and the Committee s assessment of the individual s performance. Historically, the Committee has targeted the 75th percentile of a selected peer group of companies for the combination of base salary and incentive bonus when results warrant.

While the Committee does not apply a completely formulaic approach, for fiscal 2008, the quantitative targets established by the Committee (based on input provided by management) consisted of:

- An exit production rate of 20,000 Boe per day,
- A 100% reserve replacement,
- Cash costs (lease operating expenses, general and administrative expense and taxes other than on earnings, excluding our merger and acquisition expenses) per Boe (Cash Costs/Boe) relative to the 2008 Bonus Peer Group (as defined below),
- A 20% reduction in cash costs from fiscal 2007, and
- The increase in value of our common stock relative to the 2008 Bonus Peer Group.

2008 Bonus Peer Group means the 2008 Peer Group with the addition of Energy XXI (Bermuda) Limited. The Committee included Energy XXI (Bermuda) Limited, a shelf Gulf of Mexico operating company with similar market capitalization and financial structure, in the peer group used for the fiscal 2008 quantitative bonus targets due to the anticipated acquisition of Bois d Arc Energy, Inc. by Stone Energy Corp. and the Committee s desire to use the same number of companies for purposes of peer group comparisons.

The Committee weights each of these factors equally, and the Named Executive Officers can receive up to a maximum of 200% of each quantitative target if performance exceeds the predetermined levels. The quantitative performance targets were selected because, in the analysis by management and the Committee, these targets represent stretch targets required for the Company to be a successful exploration and production (E&P) company for the following reasons:

An exit production rate of 20,000 Boe per day represented an increase of more than 40% of the average of 14,000 Boe per day at the time when the Committee established this target. In addition, the Committee considered our lower production forecast for the year.

A target of 100% reserve replacement was considered a substantial goal as compared to our negative reserve replacement for fiscal 2007, particularly in light of our limited financial budget to drill for new reserves.

The 20% cash costs reduction was considered a meaningful year over year reduction in expenses.

Cash costs per Boe and the increase in value of our common stock relative to the 2008 Bonus Peer Group each required performance above the median of the 2008 Bonus Peer Group for accomplishment, which was considered meaningful for purposes of improving stockholder value relative to our peers.

Substantially all of the targets can be compared to other E&P companies from published data, and past experience has indicated that success with these targets will usually have a positive impact on stock price, thus aligning the targets with stockholder interests.

In reviewing quantitative factors, the Committee will determine each year whether a level of performance below our targets is deserving of any bonus percentage, taking into account external factors beyond the control of the executives. For example, the Committee has, in the past, adjusted targets for extraordinary events such as the impact of hurricanes on our ability to achieve such targets. While the Committee does not set objectively ascertainable performance objectives for each individual officer, individual performance is considered by the Committee when making the bonus determinations.

A target bonus percentage of base salary is predetermined and periodically reviewed for each executive on the basis of market practices, although actual bonus payments can be significantly affected by the Committee s assessment of individual performance. The fiscal 2008 target bonus percentages for the Named Executive Officers set forth in the Summary Compensation Table are as follows: Mr. Bachmann 100%; Mr. Leary 55%; Mr. DeBrock 50%; Mr. Longon 65%; and Mr. Peper 55%.

Historically, the Committee has made the final bonus determinations around March of each fiscal year. In light of the events leading up to and culminating in the filing of Chapter 11 Cases, the Committee determined that no bonuses would be awarded for fiscal 2008.

Long-Term Equity-Based Compensation

Our long-term equity-based incentive program is designed to give our key employees a longer-term stake in our company, act as a long-term retention tool and align employee and stockholder interests by aligning compensation with growth in stockholder value. To achieve these objectives, we generally rely on a combination of different types of equity and grants with equity-like features, which are made pursuant to our 2006 Long Term Stock Incentive Plan (LTIP).

In determining the appropriate levels of long-term equity-based compensation, the Committee periodically reviews comparable compensation, as well as historical share usage and dilution analyses and the fair value of long-term compensation as a percentage of market capitalization, of a selected peer group. The Committee also periodically reviews the general mix of equity awards used by exploration and production companies of similar size and revenues in compensating executive officers. The Committee has historically targeted a dollar value of awards that would place our officers at or near the 75th percentile of equity awards provided by a selected peer group for long-term compensation.

For the fiscal 2008 equity awards to our executive officers (other than Mr. Bachmann), the Committee used a combination of stock options, stock-settled restricted share units and cash-settled restricted share units to provide long-term compensation. The Committee s rationale for selecting each type of equity award is explained in more detail below. The desired dollar value of long-term compensation was (1) based upon targeting the 75th percentile of equity awards provided by the 2008 Peer Group and (2) divided with respect to limitations set forth in our proxy statement for the 2006 Annual Meeting of Stockholders where we committed to an average annual burn rate of no more than 2.5% of our outstanding shares for calendar years 2006 through 2008 in order to obtain a favorable recommendation from Risk Metrics Group (formerly, Institutional Shareholder Services,

Table of Contents

Inc.) on the vote for the LTIP. When granting the awards, the Committee aimed to provide an allocation consisting of 25% of option shares and 75% stock-settled restricted share units to achieve its competitive benchmarking target of the 75th percentile. However, because of our burn rate commitment to Risk Metrics Group for the third and final year (2008), the Committee allocated the equity awards as follows: stock options (25%), stock-settled restricted share units (22%) and cash-settled restricted share units (53%). A significant portion of the restricted share units allocation was made by the Committee to cash-settled awards in order to achieve the desired dollar value of long-term compensation because cash-settled restricted share units are not included in the calculation of burn rate.

For purposes of the above commitment, burn rate is calculated by dividing the number of stock options, restricted shares, restricted shares units and stock-settled stock appreciation rights granted, and performance shares and stock-settled performance units paid, during each fiscal year by the number of basic shares outstanding at the end of the fiscal year. Under the calculation of burn rate, one full value share equals two option shares.

The following is a description of the material features of the awards and the Committee s rationale for awarding each type of equity award:

Stock Options. A stock option is the right to purchase, in the future, shares of common stock at a set price. Stock options may be (1) an Incentive Stock Option (ISO), which is any stock option intended to be and designated as an incentive stock option within the meaning of Section 422 of the Internal Revenue Code; or (2) a Non-Qualified Stock Option (NQSO), which is any stock option that is not an ISO. The purchase price of shares subject to any stock option must not be less than the fair market value of a share on the date of the grant of the option. Fair market value is defined as the closing price of the common stock on the date the grant is made. The maximum term of any stock option is 10 years from the date the option was granted except in the event of death or disability. The Committee can fix a shorter period, and can impose such other terms and conditions on the grant of stock options as it chooses, consistent with applicable laws and regulations. Similar to stock appreciation rights, stock options are typically granted subject to time-based vesting requirements. Likewise, stock options deliver value to an executive only to the extent that our stock price increases after the date of grant. The stock option grants made in fiscal 2008 by the Committee have a 10-year term with $1/3^{rd}$ of the options vesting and becoming exercisable on each of the first three anniversaries of the date of grant. The Committee believed that the three-year vesting term would help create a long-term incentive and strike an appropriate balance between the interests of our company, our stockholders and our officers in terms of the incentive, value creation and compensatory aspects associated of this type of equity award.

Restricted Share Units. A restricted share unit is the right to receive shares or cash at the end of a specified deferral period. In addition, restricted share units are subject to such restrictions as the Committee may impose, which may include the attainment of specified performance goals, which restrictions may lapse at the expiration of the deferral period or at earlier or later specified times, as the Committee may determine. Except as otherwise determined by the Committee, upon the termination of the participant s employment or consulting services with us, our subsidiaries and our affiliates during the applicable deferral period or upon failure to satisfy any other conditions precedent to the delivery of the shares, restricted share units that are at that time subject to deferral or restriction will be forfeited. Restricted share units provide value in the form of stock while resulting in lower share usage and lower dilution than the use of certain other types of equity awards. In addition, the vesting conditions and opportunity for long-term capital appreciation, which are characteristic of restricted share units, help us achieve our objectives of management retention and linking pay to our long-term stockholder value. Restricted share units do not offer dividend or voting rights until they vest and shares are subsequently released to the grantee. These awards are designed to build executive ownership, retain executives, and align compensation with the achievement of creating stockholder value. We believe restricted shares can be a strong motivational tool for our employees. Restricted share awards provide some value to an employee during periods of stock market volatility, whereas other forms of equity compensation, such as stock options, may have limited perceived value and may do little to retain and motivate employees when the current value of our stock is less than the option price. The fiscal 2008 grants of stock-settled restricted share units and cash-settled restricted share units by the Committee vest in 1/3rd increments on each of the first three anniversaries of the date of grant. The Committee believed that the three-year vesting term would help create a long-term incentive and strike an appropriate balance between the interests of our company, our stockholders and our officers in terms of the incentive, value creation and compensatory aspects associated of this type of equity award.

In April 2008, the Committee recommended, and the independent directors approved, long-term equity compensation for Mr. Bachmann in the form of an award of 500,000 cash-settled share appreciation rights. The award was based on data calculated by Frederic W. Cook & Co., which targeted the 75th percentile of the 2008 Peer Group, consistent with the Committee s compensation philosophy. The following is a description of the material features of this award and the Committee s rationale for awarding this type of equity award:

Cash-Settled Share Appreciation Rights. A share appreciation right, or an SAR, is the right to receive upon the exercise of each share the excess of (1) the closing price of one share of common stock on the date of the exercise over (2) the exercise price per share of the SAR, as determined by the Committee as of the date of the grant of the SAR (which shall not be less than the fair market value of the share on the date of the grant of the SAR). The maximum term of any SAR is 10 years from the date the SAR was granted except in the event of death or disability. The Committee can fix a shorter period, and can impose such other terms and conditions on the grant of SARs as it chooses, consistent with applicable laws and regulations. The Committee granted Mr. Bachmann cash-settled SARs in fiscal 2008 instead of stock-settled awards in order to maintain our burn rate commitment and because these equity awards deliver value to him only to the extent that our stock price increases after the date of grant. However, unlike options, SARs do not require the payment of an exercise price. Because this grant is cash- settled, it does not use shares from the LTIP s authorized stock pool because upon exercise, the SAR s delivers only the cash value of the number of shares equivalent in value to the appreciation in the underlying stock. The grant of SAR s to Mr. Bachmann was made with a term of 10 years with 1/3 of the covered shares vesting and becoming exercisable on each of the first three anniversaries of the date of grant. The Committee believed the three-year vesting term would help create a long-term incentive and strike an appropriate balance between the interests of our company, our stockholders and Mr. Bachmann in terms of the incentive, value creation and compensatory aspects of this equity award.

Other Benefits

Health and Welfare Benefits

Our Named Executive Officers are eligible to participate in all of our employee health and welfare benefit plans on the same basis as other employees (subject to applicable law) to meet their health and welfare needs. These plans include medical, dental, vision, group life, long-term and short-term disability, accidental death and dismemberment insurance, as well as medical and dependent care flexible spending accounts. These benefits are provided so as to assure that we are able to competitively attract and retain officers and other employees. This is a fixed component of base compensation, and the benefits are provided on a non-discriminatory basis to all employees.

Retirement Benefits

We offer a 401(k) profit sharing plan for the benefit of our employees, including our Named Executive Officers, which is designed to assist our employees in providing for their retirement. Employees may begin participating in the plan at the beginning of the first fiscal quarter following the date of hire for the employee. Under the plan, eligible employees may elect to defer a portion of their earnings up to the annual maximum allowed by IRS regulations. We match 100% of each participant s contribution up to 6% of the participant s base compensation. Until 2009, our matching contributions were made in our common stock. During 2009, our plan was amended to require matching contributions to be made in cash. Our matching contribution vests 50% per year for the first two years of the participant s employment.

Perquisites

We believe that the total mix of compensation and other benefits provided to our executive officers is comprehensive and competitive, and our executive officers are not entitled to operate under different standards than other employees. Accordingly, we do not have programs for providing personal benefit perquisites to our executive officers, such as permanent lodging or defraying the cost of personal entertainment or family travel. We provide air and other travel for our executive officers for business purposes only, consistent with the same standards of other employees.

Severance and Change of Control Payments

We maintain the Severance Plan for certain key employees. Until June 2009, we maintained Severance Agreements with certain of our current and former executive officers. These agreements, which are described more fully in Potential Payments Upon a Termination or Change in Control, were designed to meet the following objectives:

- To meet market conditions to provide common and competitive benefits in the energy industry, which, in recent history, have experienced an elevated level of merger/acquisition activity.

- To be used as recruitment and retention tools in light of current industry dynamics, in particular by mitigating the distraction of potential job loss. This objective is particularly relevant in our case, as we are a relatively small company. Additionally, we are now operating as a debtor-in-possession as a result of filing the Chapter 11 Cases. As a result of the financial protection provided, executives are better positioned to make the best decisions to increase shareholder value.

- To provide protection for previous amounts earned.

- We believe it is prudent to put these agreements in place when appropriate consideration can be given to their consequences rather than developing strategies under the pressure of an imminent transaction.

Our Fiscal 2009 Executive Compensation Program

Commencing in the first half of fiscal 2009 and continuing through the date of this filing, we have experienced major changes in the management of our company. Our Board of Directors declined from eleven to five members during the first quarter of 2009. In addition, on March 1, 2009, Joseph T. Leary resigned as our Executive Vice President and Chief Financial Officer. On March 15, 2009, Richard A. Bachmann resigned as our Chairman and Chief Executive Officer and we engaged Alan D. Bell as our Chief Restructuring Officer. In July 2009, we announced the designation of Alan D. Bell as principal executive officer and Tiffany J. Thom as principal financial officer. These management changes, in addition to our filing a voluntary petition (*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, in the United States Bankruptcy Court, led to changes in our executive compensation program.

As a result of the Plan Support Agreement, various incentive and retention plans and agreements that existed for certain of our executive officers required amending, renegotiating, and/or restructuring prior to the effective date of a confirmed plan of reorganization. As discussed in more detail under Part II, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operation Recent Events Restructure of Prepetition Employee Arrangements, the provisions of these plans and agreements were amended. Further, we established a Non-Insider Employee Retention Plan and a Senior Management Employee Plan. Finally, the Severance Agreements with certain executive officers were terminated in exchange for the executives receiving an unsecured claim for rejection damages.

Table of Contents

Policy on Deductibility of Compensation

Section 162(m) of the Internal Revenue Code of 1986 limits the deductibility for federal income taxes of compensation in excess of $1.0 million paid to a publicly-held company s chief executive officer and any of the other four highest-paid executive officers, except for performance-based compensation. The Committee is aware of this limitation and generally considers the effects of Section 162(m) on our company when making compensation decisions, but has not yet adopted a formal policy with respect to the Section 162(m) limitation.

Accounting Treatment of Executive Compensation Decisions

We account for stock-based awards based on their grant date fair value, as determined under SFAS No. 123(R). Compensation expense for these awards, to the extent such awards are expected to vest, is recognized over the requisite service period of the award (or to an employee s eligible retirement date, if earlier). If the award is subject to a performance condition, however, the cost will vary based on our estimate of the number of shares that ultimately will vest over the requisite service or other period over which the performance condition is expected to be achieved. In connection with its approval of stock-based awards, the Committee is cognizant of and sensitive to the impact of such awards on stockholder dilution.

Stock Ownership Guidelines

The Board adopted Executive Stock Ownership Guidelines that generally require our executive officers to maintain a share ownership equal to 50% of the profit shares acquired under our equity compensation plans. Profit shares means the shares held by an executive officer as a result of the exercise of stock options, the lapsing of restrictions on restricted stock and restricted share units and the earning of performance shares, after giving effect to shares sold or netted to pay any exercise price or tax withholding amounts related to such award.

Table of Contents

Summary Compensation Table

The following table summarizes, with respect to our Named Executive Officers, information relating to the compensation earned for services rendered in all capacities.

Summary Compensation Table for the Year Ended December 31, 2008

Name and Principal Position	Year	Salary ($)	Bonus (1) ($)	Stock Awards (2) ($)	Option Awards (3) ($)	Non-Equity Incentive Plan Compensation (4) ($)	All Other Compensation (5) ($)	Total ($)
Richard A. Bachmann (6)	2008	525,000		242,720	530,031		21,694	1,319,445
Former Chairman and Chief Executive Officer	2007	500,000		248,120	825,977		21,394	1,595,491
	2006	440,000		649,580	890,594	300,000	20,914	2,301,088
Joseph T. Leary (7)	2008	265,000		117,514	352,630		3,797	738,941
Former Executive Vice President and Chief Financial	2007	92,788	50,000		132,863		1,366	277,017
Officer	2006							
Thomas D. DeBrock (8)	2008	270,000	120,000	260,930	147,671		15,892	814,493
Senior Vice President of Exploration	2007	226,620	223,500	419,241	64,795		14,883	949,039
	2006							
Stephen D. Longon (9)	2008	288,307		142,750	107,402	60,000	16,364	614,823
Executive Vice President and Chief Operating Officer	2007							
	2006							
John H. Peper	2008	275,000		144,166	152,711		17,700	589,577
Executive Vice President, General Counsel and Corporate	2007	250,000	200,000	92,720	280,294		17,142	840,156
Secretary	2006	236,000		149,425	313,471	88,264	27,953	815,113

(1) Amounts for 2007 include Chairman s Awards paid to Messrs. Peper and DeBrock.

(2) Amounts in this column reflect compensation expense recorded in our consolidated financial statements for each Named Executive Officer for the fiscal years ended December 31, 2008, 2007 and 2006, and includes grants made in previous years for which compensation expense is required to be recognized in accordance with SFAS No. 123(R). The expense has been calculated based on the grant date fair value of the respective awards offset by the fiscal 2008 reversal of a portion of the amounts expensed in 2007 due to reductions in assumptions regarding payout levels and in certain cases, share price. The amounts reported have been adjusted to eliminate service-based forfeiture assumptions. Please refer to Notes 2(j) and 15 in Part II, Item 8 of this Annual Report and to our Annual Reports on Form 10-K for the fiscal years ended December 31, 2007 and 2006, for a discussion of the assumptions used in computing the grant date fair value of stock based compensation awards. These amounts reflect our accounting expense for these awards and do not correspond to the actual value that might be realized by the Named Executive Officers. See Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table below for a description of the material features of these awards.

(3) Amounts in this column reflect compensation expense recorded in our consolidated financial statements for each Named Executive Officer for the fiscal years ended December 31, 2008, 2007 and 2006, and includes grants made in previous years for which compensation expense is required to be recognized in accordance with SFAS No. 123(R). The expense has been calculated based on the grant date fair value of the respective awards offset by the fiscal 2008 reversal of a portion of the amounts expensed in 2007 due to reductions in assumptions regarding payout levels and in certain cases, share price. The amounts reported have been adjusted to eliminate service-based forfeiture assumptions. Please refer to Notes 2(j) and 15 in Part II, Item 8 of this Annual Report for a discussion of the assumptions used in computing the grant date fair value of stock based compensation awards. These amounts reflect our accounting expense for these awards and do not correspond to the actual value that might be realized by the Named Executive Officers. See Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table below for a description of the material features of these awards.

(4)

Amounts reflected in this column are paid pursuant to our incentive compensation plan as described under Compensation Discussion and Analysis Annual Cash Incentive Bonus.

(5) The amounts represent the dollar value of term life insurance premiums paid by us for the benefit of the Named Executive Officers, the dollar value of the company match to our 401(k) Plan on the employees behalf, and reimbursement of relocation expenses. For 2008, (a) the life insurance premiums for Messrs. Bachmann, Peper, Leary, Longon and DeBrock were $6,574, $2,580, $2,477, $1,354 and $882 respectively; and (b) the value of the 401(k) match for Messrs. Bachmann, Peper, Longon and DeBrock was $13,800, $13,800, $13,800, and $13,800 respectively.

118

Table of Contents

(6) Mr. Bachmann resigned in March 2009.

(7) Mr. Leary became an executive officer in August 2007 and was paid a cash bonus of $50,000 upon commencement of employment. Mr. Leary resigned in March 2009.

(8) Mr. DeBrock became an executive officer in August 2007. Amounts included in the column titled Bonus reflect payments as described under Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table. Previously, the $120,000 payment in 2007 was reported in the column titled All Other Compensation.

(9) Mr. Longon became an executive officer in February 2008.

Grants of Plan-Based Awards Table

The following table provides information concerning each grant of an award made to our Named Executive Officers under any plan, including awards, if any, that have been transferred during the fiscal year ended December 31, 2008.

Grants of Plan-Based Awards for the Year Ended December 31, 2008

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards (1) Threshold ($)	Target ($)	Maximum (2) ($)	All Other Stock Awards: Number of Shares of Stock or Units (#)	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards ($/Sh)	Closing Price on Grant Date ($/Sh)	Grant Date Fair Value of Stock and Option Awards (3) ($)
Richard A. Bachmann		0	525,000	N/A					
	April 21, 2008					500,000	11.74	11.74	
Joseph T. Leary		0	145,750	N/A					
	April 11, 2008					53,285	10.58	10.58	228,947
					63,191			10.58	668,561
Thomas D. DeBrock		0	135,000	N/A					
	April 11, 2008					38,959	10.58	10.58	167,393
					46,201			10.58	488,807
Stephen D. Longon		0	120,000	N/A					
	April 11, 2008					38,959	10.58	10.58	167,393
					46,201			10.58	488,807
John H. Peper		0	151,250	N/A					
	April 11, 2008					53,285	10.58	10.58	228,947
					63,191			10.58	668,561

(1) Amounts actually paid are reflected in the column titled Non-Equity Incentive Plan Compensation found on the Summary Compensation Table above. For additional information see Compensation Discussion and Analysis Annual Cash Incentive Bonus.

(2) While executive officers may earn up to a maximum of 200% of each quantitative target under our annual incentive bonus program, the Committee retains discretion to award officers additional amounts based on external factors beyond the control of the officers as well as individual performance by the officers.

(3) Amounts reflect the grant date fair value of the respective awards computed in accordance with SFAS No. 123(R). Please refer to Notes 2 and 15 in Part II, Item 8 of this Annual Report for a discussion of the assumptions used in computing the grant date fair value of stock based compensation awards. These amounts reflect our accounting expense for these awards and do not correspond to the actual value that might be realized by the Named Executive Officer.

Table of Contents

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

The following is a discussion of material factors necessary to an understanding of the information disclosed in the Summary Compensation Table and the Grants of Plan-Based Awards Table above.

Salary and Cash Incentive Awards in Proportion to Total Compensation

The following table sets forth the percentage of each Named Executive Officer s total compensation that we paid in the form of base salary and bonus.

Name	Year	Percentage of Total Compensation
Richard A. Bachmann (1)	2008	40%
	2007	31%
	2006	19%
Joseph T. Leary (2)	2008	36%
	2007	52%
	2006	
Thomas D. DeBrock (3)	2008	48%
	2007	47%
	2006	
Stephen D. Longon (4)	2008	47%
	2007	
	2006	
John H. Peper	2008	47%
	2007	54%
	2006	29%

(1) Mr. Bachmann resigned in March 2009.

(2) Mr. Leary became an executive officer in August 2007 and resigned in March 2009.

(3) Mr. DeBrock became an executive officer in August 2007.

(4) Mr. Longon became an executive officer in February 2008.

Bonuses

Mr. Leary received a cash payment of $50,000 during fiscal 2007 upon commencement of employment. As a recipient of the Chairman s Award, Mr. Peper received a cash payment of $200,000 during fiscal 2007.

Mr. DeBrock received a cash payment of $120,000 in each of fiscal 2007 and 2008 pursuant to the terms of an agreement with us as described below under the caption Employment Agreements. As a recipient of the Chairman s Award, Mr. DeBrock received a cash payment of $103,500 during fiscal 2007.

Messrs. Bachmann and Longon did not receive bonuses during fiscal 2006, 2007 or 2008; however, Messrs. Bachmann and Longon each received a cash award under our Annual Cash Bonus Incentive Plan for fiscal 2006 and fiscal 2008, respectively, as further described under the caption Non-Equity Incentive Plan Compensation below.

Stock Awards

Pursuant to our LTIP, we awarded stock-settled restricted share units and cash-settled restricted share units to our Named Executive Officers. These grants are described in further detail under the heading Compensation Discussion and Analysis Long-Term Equity-Based Compensation.

Table of Contents

Option Awards

Pursuant to our LTIP, we awarded stock options and stock appreciation rights to certain of our Named Executive Officers. These grants are described in further detail under the heading Compensation Discussion and Analysis Long-Term Equity-Based Compensation.

Non-Equity Incentive Plan Compensation

The non-equity incentive plan compensation set forth in the Summary Compensation Table above reflects annual cash incentive bonus compensation under our annual cash incentive bonus program. Compensation is earned under this program based upon the achievement of pre-established performance targets. More information is set forth under the heading Compensation Discussion and Analysis Annual Cash Incentive Bonus.

Employment Agreements

Under our offer letter to Mr. Leary dated August 15, 2007, he was entitled to an annual base salary of $250,000. In addition, Mr. Leary received a sign-on bonus of $50,000, an option with a 10-year term to purchase 100,000 shares of common stock, which vested ratably over three years at an exercise price equal to the closing price of our common stock on the date of the grant and 30,000 cash-settled restricted share units which vested on the third anniversary of the date his employment commenced. Mr. Leary s annual bonus target was 55% of base pay. Mr. Leary resigned from our company in March 2009.

Under our offer letter to Mr. Longon dated June 11, 2007, Mr. Longon was entitled to an annual base salary of $224,000. Mr. Longon also received a sign-on bonus of $50,000, an option with a 10-year term to purchase 10,000 shares of common stock, which vests ratably over three years at an exercise price equal to the closing price of our common stock on the date of the grant and 10,000 cash-settled restricted share units which vest on the third anniversary of the date his employment commenced. Mr. Longon s annual bonus target was 25% of base pay.

We entered into an agreement with Mr. DeBrock on November 29, 2007, pursuant to which we agreed to pay Mr. DeBrock $120,000 in cash on December 1, 2007 and on December 1 of each of the four succeeding years provided that Mr. DeBrock remained employed by us through the applicable payment date. As described in more detail below under Potential Payments Upon Termination or Change in Control, we entered into a settlement agreement with Mr. DeBrock in July 2009, which terminated this agreement.

We do not have employment agreements with any of the other Named Executive Officers.

Additional Information

We have provided additional information regarding the compensation we pay to our Named Executive Officers under Compensation Discussion and Analysis Other Benefits and Compensation Discussion and Analysis Severance and Change of Control Payments.

Table of Contents

Outstanding Equity Awards at Fiscal Year-End Table

The following table provides information concerning unexercised options, stock that has not vested, and equity incentive plan awards for our Named Executive Officers.

Outstanding Equity Awards as of December 31, 2008

	Option Awards				Stock Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested (1) ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (2) (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested (1) ($)
Richard A. Bachmann	100,000		$ 10.80	04/30/2011				
	53,334		$ 10.07	05/06/2013				
	200,000		$ 13.58	05/13/2014				
	62,000		$ 25.07	03/24/2015				
	74,620	37,310 (3)	$ 22.98	03/23/2016				
	41,773	20,886 (4)	$ 18.00	08/03/2016				
	26,083	52,165 (5)	$ 17.27	06/01/2017				
		500,000 (6)	$ 11.74	04/21/2018				
					5,549 (3)	7,491		
					3,034 (4)	4,096		
							67,058 (13)	90,530
Joseph T. Leary	33,334	66,666 (7)	$ 13.26	08/21/2017				
		53,285 (8)	$ 10.58	04/11/2018				
					18,536 (8)	25,024		
							30,000 (14)	40,500
							44,655 (8)	60,284
Stephen D. Longon	3,334	6,666 (9)	$ 17.45	07/09/2017				
		38,959 (8)	$ 10.58	04/11/2018				
					10,000 (15)	13,500		
					13,552 (8)	18,295		
							10,000 (15)	13,500
							32,649 (8)	44,076

Table of Contents

	Option Awards				Stock Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested (1) ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (2) (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested (1) ($)
Thomas D. DeBrock	15,000		$ 13.58	05/13/2014				
	15,000		$ 27.34	03/17/2015				
	6,667	3,333 [10]	$ 22.31	03/16/2016				
		38,959 [8]	$ 10.58	04/11/2018				
					25,000 [16]	33,750		
					1,667 [10]	2,250		
					2,000 [10]	2,700		
					6,666 [17]	8,999		
					13,552 [8]	18,295		
							32,649 [8]	44,076
John H. Peper	75,000		$ 7.98	01/17/2012				
	23,333		$ 10.07	05/06/2013				
	33,500		$ 13.58	05/13/2014				
	13,400		$ 27.34	03/17/2015				
		100,000 [11]	$ 26.59	07/22/2015				
	13,454	6,727 [10]	$ 22.31	03/16/2016				
	6,727	3,363 [3]	$ 22.98	03/23/2016				
	7,015	3,508 [4]	$ 18.00	08/03/2016				
	6,029	12,057 [12]	$ 16.82	05/30/2017				
		53,285 [8]	$ 10.58	04/11/2008				
					1,501 [3]	2,026		
					510 [4]	689		
					18,536 [8]	25,024		
							15,500 [12]	20,925
							44,655 [8]	60,284

(1) Based on the closing price of our common stock of $1.35 on December 31, 2008.

(2) Represents unvested cash-settled restricted share units.

(3) Represents the underlying option shares for unexercisable stock options that were granted on March 23, 2006, which became exercisable on March 23, 2009. For Mr. Bachmann, represents the unvested restricted shares that were granted on March 23, 2006, which vested on March 23, 2009. For Mr. Peper, represents the unvested restricted shares granted on March 23, 2006, which vested on March 23, 2009.

(4) Represents the underlying option shares for unexercisable stock options that were granted on August 3, 2006, which become exercisable on August 3, 2009. Represents the remaining unvested restricted shares that were granted on August 3, 2006, which will vest on August 3, 2009, except for Mr. Bachmann s shares, which were forfeited on March 15, 2009.

(5)

Represents one-half of the underlying option shares for unexercisable stock options that were granted on June 1, 2007, which became exercisable on June 1, 2009. The remaining one-half were scheduled to become exercisable on June 1, 2010, but were forfeited on March 15, 2009.

(6) Represents one-third of the underlying rights for unexercisable stock appreciation rights that were granted on April 21, 2008, which became exercisable on April 21, 2009. The remaining one-third were scheduled to become exercisable on each of April 21, 2010 and April 21, 2011, but were forfeited on March 15, 2009.

(7) Represents one-half of the underlying option shares for unexercisable stock options that were granted on August 21, 2007 that were scheduled to become exercisable on each of August 21, 2009 and August 21, 2010, but were forfeited on March 1, 2009.

(8) Represents one-third of the underlying shares for unexercisable stock options, one-third of the unvested restricted shares and one-third of the unvested cash-settled restricted share units that were granted on April 11, 2008, which became exercisable or vested (as applicable) on April 11, 2009 and an additional one-third that will become exercisable or will vest (as applicable) on each of April 11, 2010 and April 11, 2011, except for Mr. Leary s shares, which were forfeited on March 1, 2009.

(9) Represents one-half of the underlying option shares for unexercisable stock options that were granted on July 9, 2007, which became exercisable on July 9, 2009. The remaining one-half will become exercisable on July 9, 2010.

(10) Represents the underlying option shares for unexercisable stock options and unvested restricted shares that were granted on March 16, 2006, which became exercisable on March 16, 2009.

(11) Represents the underlying option shares for the unexercisable stock options that were granted on July 22, 2005, which will become exercisable on July 22, 2010.

(12) Represents one-half of the underlying option shares for unexercisable stock options and unvested cash-settled restricted share units that were granted on May 30, 2007, which became exercisable on May 30, 2009. The remaining one-half will become exercisable on May 30, 2010.

(13) Represents one-half of the unvested cash-settled restricted share units that were granted on June 1, 2007, which became exercisable on March 16, 2009. The remaining one-half were scheduled to become exercisable on June 1, 2010, but were forfeited on March 15, 2009.

(14) Represents all of the unvested cash-settled restricted share units that were granted on August 21, 2007, which were scheduled to become exercisable on August 21, 2010, but were forfeited on March 1, 2009.

(15) Represents all of the unvested restricted shares and unvested cash-settled restricted share units that were granted on July 9, 2007, which will become exercisable on July 9, 2010.

(16) Represents one-half of the unvested restricted shares that were granted on July 22, 2005, which became exercisable on July 22, 2009. The remaining one-half will become exercisable on July 22, 2011.

(17) Represents one-half of the unvested restricted shares that were granted on April 3, 2007, which became exercisable on April 3, 2009. The remaining one-half will become exercisable on April 3, 2010.

Option Exercises and Stock Vested Table

The following table provides information concerning each vesting of stock, including stock-settled restricted share units, cash-settled restricted share units and similar instruments, during the fiscal year ended December 31, 2008 on an aggregated basis with respect to each of our Named Executive Officers. Our Named Executive Officers did not exercise any stock options during the fiscal year ended December 31, 2008.

Option Exercises and Stock Vested for the Year Ended December 31, 2008

	Stock Awards	
Name	**Number of Shares Acquired on Vesting**	**Value Realized on Vesting**

	(#)	($)
Richard A. Bachmann (1)	42,113	590,527
Joseph T. Leary		
Thomas D. DeBrock	9,500	96,836
Stephen D. Longon		
John H. Peper (2)	9,759	136,043

(1) Includes 33,530 cash-settled restricted share units that vested during fiscal 2008 for a value realized on vesting of $505,297, reflecting a price of $15.07, per cash-settled restricted share unit.

(2) Includes 7,750 cash-settled restricted share units that vested during fiscal 2008 for a value realized on vesting of $116,792, reflecting a price of $15.07, per cash-settled restricted share unit.

Potential Payments Upon Termination or Change of Control

We do not have any contracts, agreements, plans or arrangements that provide severance benefits to our Named Executive Officers if they terminate employment prior to our change of control. However, certain of our current and former executive officers, Messrs. Bachmann, Leary, Longon and Peper, entered into Severance Agreements with us. Messrs. Bachmann and Peper entered into their respective agreements in March 2005, Mr. Leary entered into a Severance Agreement when he joined us in August 2007, Mr. Longon entered into his agreement in July 2008, and each of the Severance Agreements, following various amendments, contained a termination date of March 28, 2010. In addition, we have Severance Plan (together with the Severance Agreements, our Severance Program) for certain key employees, including Mr. DeBrock.

Payments Upon a Change in Control

The Severance Program provides that, upon the occurrence of a change of control (as defined below), all equity awards granted to participants will become fully vested, all stock options and share appreciation rights will become fully exercisable and all restrictions on restricted shares and restricted share units will lapse. With respect to performance shares or other awards contingent on satisfaction of performance measures, the performance cycle will end as of the date of the change of control, and the participant will vest in the number of shares that would have been earned if the performance cycle had ended as of the end of the period covered by the most recently issued year-end financial statement plus such additional number of shares as the Committee determines in respect of any period of the performance cycle not covered by such year-end statement. A termination of employment without cause (as defined below) or for good reason (as defined below) is not a condition for such benefits. Thus, if a change of control were to occur, the Named Executive Officers would receive the benefit of the accelerated vesting of stock options, restricted shares, restricted share units, cash-settled restricted share units, cash-settled share appreciation rights and performance shares as shown in the table below even if the Named Executive Officer s employment does not terminate. Pursuant to the terms of outstanding stock options and cash-settled share appreciation rights, in the event of a change of control, such options and cash-settled share appreciation rights would remain exercisable until the expiration of their 10-year term. Under the terms of outstanding restricted shares, restricted share units, cash-settled restricted share units and performance shares, in the absence of a change of control, such awards would be forfeited in the event of a termination of employment for any reason. Under the terms of outstanding stock options and cash-settled share appreciation rights, in the absence of a change of control, the following rules would apply upon a termination of employment: (1) in the case of a termination for any reason other than death, disability (defined generally as an individual s inability, from mental or physical impairment, for a 90 day period, to perform that individual s expected duties and functions) or retirement (defined to mean a voluntary termination on or after age 55 with at least five years of service), unvested options and cash-settled share appreciation rights would be forfeited and vested options and cash-settled share appreciation rights would remain exercisable for 30 days following termination of employment (but not beyond their expiration date), and (2) in the case of a termination by reason of death, disability or retirement, options and cash-settled share appreciation rights would continue to vest through December 31st of the year of termination of employment, unvested options and cash-settled share appreciation rights would be forfeited as of such December 31st, and vested options and cash-settled share appreciation rights would remain exercisable for three years following termination of employment (but not beyond their expiration date).

Payments Upon Certain Terminations of Employment in Connection with a Change in Control

In addition to the accelerated equity compensation awards, participants in the Severance Program are entitled to receive certain benefits in the event of their termination of employment either by reason of an involuntary termination by us without cause (as defined below) or a voluntary termination by the executive for good reason (as defined below) occurring within two years after a change of control. Upon the occurrence of both the change in control and a qualifying termination of employment, an eligible participant would be entitled to receive between one and one half and three times the sum of (1) the participant s annual rate of base salary for the year of termination and (2) the participant s average annual bonus from us for the three calendar years preceding the calendar year in which such termination of employment occurs (or, if the participant was employed for less than three years, the greater of the average annual bonus for all of the calendar years such individual was employed and the target bonus for the calendar year of termination). Messrs. Bachmann, Leary, Longon and Peper are entitled to receive three times, and Mr. DeBrock is entitled to receive two times, the sum described in the preceding sentence. Payments are to be paid in a lump sum in cash within 30 days following termination.

In addition, participants who become entitled to severance benefits will continue to receive the medical, dental and life insurance benefits in existence at the time of the change of control for a specified period of time (18 months for each of our Named Executive Officers), provided that the participant continues to pay the same portion of the required premium for such coverage as was required prior to termination. In the case of a participant who becomes entitled to severance benefits, if the participant has not, by the time of his or her termination of employment, received a bonus for the calendar year before the calendar year of termination of employment, the participant will receive a bonus for that year in an amount equal to his or her target bonus opportunity for that year, payable in a lump sum payment within 30 days of the individual s termination of employment.

If any payments are subject to the excise tax on excess parachute payments under Section 280G of the Internal Revenue Code of 1986, payments to the participant will be reduced until no amount payable to the participant would constitute an excess parachute payment, provided that no such reduction will be made if the net after-tax payment to which the participant would otherwise be entitled without such reduction would be greater than the net after-tax payment, in each case, after taking into account Federal, state, local or other income and excise taxes, to the participant resulting from the receipt of such payments with such reduction.

For purposes of the Severance Program and awards under the LTIP, a change of control generally includes any of the following events: (1) an acquisition by any person of 25% or more of the securities entitled to vote in the election of directors, (2) the current directors, or their approved successors, no longer constitute a majority of the Board, (3) a merger or similar transaction is consummated which results in the holders of our common stock owning 50% or less of the surviving or transferee entity s securities entitled to vote generally in the election of directors, or (4) approval of a plan of liquidation or disposition of all or substantially all of our assets. A termination for cause includes an individual s termination due to a conviction of a felony, dishonesty, failure to perform duties, insubordination, theft, wrongful disclosure of confidential information, undisclosed conflicts of interest, violation of our employee policies, or competing with us for personal benefit. Good reason may exist if we reduce an individual s base salary, eliminate or significantly reduce a material benefit under any of our employee benefit plans, take away an individual s titles or positions or significantly reduce the individuals duties and responsibilities, or require the individual to relocate outside of the greater metropolitan area to which the individual was performing services for us immediately prior to the applicable change in control event.

The following table shows the amounts that would be payable to our Named Executive Officers, assuming there was a change of control as of December 31, 2008 and/or a termination of employment that would qualify the Named Executive Officer for the benefits described below occurred on December 31, 2008. For purposes of calculating the amounts set forth below, we have made the following assumptions:

- our Named Executive Officers have the same rights as other employees to receive benefits they have earned under our broad-based benefit programs, such as their vested account balances under our 401(k) plan, thus such amounts are not included below;

- all earned vacation was taken and all salary and reimbursable expenses were current at the time of the individual s termination of employment, thus there is no need to pay out any amounts related to these items in addition to the amounts below;

- the closing price of our common stock on December 31, 2008 was $1.35;

- no amounts are included in the Equity Acceleration rows for any stock options, as the exercise price for each of the stock options our Named Executive Officers held as of December 31, 2008 was higher than the price of our common stock on that day and considered underwater ;

Table of Contents

though in the case of a termination by reason of death, disability or retirement, options and cash-settled share appreciation rights would continue to vest through December 31st of the year of termination of employment, as the numbers below are calculated as of a termination upon December 31, 2008, no additional acceleration of equity awards would occur upon a death, disability or retirement of the executive; and

the numbers below are only estimated amounts assuming the applicable event occurred on December 31, 2008, and amounts could not be determined with any certainty until an actual termination or change of control took place.

Potential Payments Upon a Termination or Change in Control Table as of December 31, 2008

Executive Officer	Termination by Good Reason or without Cause in connection with a Change in Control $	Change in Control $
Richard A. Bachmann (1)		
Salary and Bonus	2,290,000	N/A
Equity Acceleration	102,117	102,117
Medical Benefit Continuation	17,028	N/A
Total	2,409,145	102,117
Joseph T. Leary (2)		
Salary and Bonus	1,232,250	N/A
Equity Acceleration	125,808	125,808
Medical Benefit Continuation	8,617	N/A
Total	1,366,675	125,808
Thomas D. DeBrock (3)		
Salary and Bonus	685,000	N/A
Equity Acceleration	110,070	110,070
Medical Benefit Continuation	21,436	N/A
Total	816,506	110,070
Stephen D. Longon (3)		
Salary and Bonus	1,683,000	N/A
Equity Acceleration	89,371	89,371
Medical Benefit Continuation	15,922	N/A
Total	1,788,293	89,371
John H. Peper (3)		
Salary and Bonus	1,043,234	N/A
Equity Acceleration	108,948	108,948
Medical Benefit Continuation	21,381	N/A
Total	1,173,563	108,948

(1) We entered into an Offer Agreement with Mr. Bachmann in connection with his termination of employment in March 2009. The Offer Agreement set forth the terms and conditions regarding his severance payments, including Mr. Bachmann s agreement to waive all rights he might have previously had to compensation and benefits prior to the execution of the Offer Agreement, as well as a general waiver of claims and actions in our favor. In exchange for these waivers Mr. Bachmann received a one-time payment of $110,000, as well as the accelerated vesting of his 5,549 restricted stock units, and 33,529 cash-settled restricted stock units. Thus, the amounts in the table above are no longer potential liabilities we have with respect to Mr. Bachmann, as he has received all potential payments pursuant to the Offer Agreement.

(2) We are no longer under an obligation to provide Mr. Leary with the payments disclosed in the table above as Mr. Leary also resigned in March 2009, and he did not receive any compensation from us in connection with his termination of employment.

(3) Messrs. DeBrock, Longon and Peper each have entered into a settlement agreement with us following December 31, 2008 that significantly impacts their potential payments upon a termination of employment or a change in control. Please see Actions Following December 31, 2008 below for further details.

Actions Following December 31, 2008

As part of our reorganization, the bankruptcy court approved our entrance into various settlement agreements with a number of our employees that held outstanding equity compensation awards or unpaid bonuses payments. These settlement agreements provided the individual with a cash payment in lieu of his or her outstanding equity or bonus awards, and cancelled the outstanding equity awards that individual previously held. Thus the amounts disclosed in the table above are not necessarily indicative of the amounts that we could be potentially liable to provide to each of the Named Executive Officers that are still employed with us at the time of this filing. Mr. DeBrock s execution of a settlement agreement provided him with a payment of $60,000 in exchange for the cancellation of his outstanding retention payments and cash-settled equity awards. For Messrs. Longon and Peper, the settlement agreements cancelled our Severance Agreement obligations and provided each of these executives with a claim against us for $340,000 and $275,000, respectively, and the executives waived all rights to the future payments pursuant to their Severance Agreements. These claims are being treated as unsecured claims, which would be paid in full under the Plan. The Severance Plan was amended effective April 29, 2009 to modify the definition of a change in control. The events that generally constitute a change in control were not changed, but due to the unique financial situation we were in pending our reorganization, our Board determined that various transactions related to our bankruptcy should not trigger the change of control definition in the Severance Plan. The definition was amended to explicitly exclude the filing of the voluntary petition of bankruptcy, our exit from bankruptcy, or any transaction related to our bankruptcy from activating the change in control definition, although following our exit from bankruptcy, the definition shall apply to all events and transactions as it did prior to our bankruptcy filing. This also means that no events relating to our bankruptcy will trigger the two year protection period that would otherwise immediately follow a change in control under the Severance Plan.

Director Compensation

General

At least once a year, the Committee reviews the total direct compensation paid to our non-employee directors and makes recommendations to the Board for final approval. The purpose of the Committee s review is to ensure that the level of compensation received by our non-employee directors is appropriate to attract and retain a diverse group of individuals with the breadth of experience necessary to perform the Board s duties, and to fairly compensate such individuals for their service as our directors. The Committee s review typically occurs prior to our Annual Meeting of Stockholders, and any changes recommended by the Committee and adopted by the Board are typically effective commencing with the date of the Annual Meeting. The Committee has engaged Frederic W. Cook & Co., Inc. to provide an analysis of total director compensation received by our non-employee directors, and the Committee typically targets the 75th percentile of a peer group of companies for total director compensation.

For fiscal 2008, the peer group of companies comprising the analysis by Frederic W. Cook & Co., Inc. included the 2008 Peer Group used for executive compensation decisions by the Committee.

The following table sets forth a summary of the compensation we paid to our non-employee directors during the fiscal year ended December 31, 2008. Directors who are our full-time employees receive no compensation for serving as directors on the Board.

Director Compensation for the Year Ended December 31, 2008

Name	Fees Earned or Paid in Cash ($)	Stock Awards (1) ($)	Option Awards (2) ($)	All Other Compensation ($)	Total ($)
John C. Bumgarner, Jr. (3)	56,000	125,615	10,248		191,863
Jerry D. Carlisle	63,500	106,240	10,248		179,988
Harold D. Carter (4)	64,500	101,657	10,248		176,405
Enoch L. Dawkins (5)	47,000	99,365	10,248		156,613
Dr. Norman C. Francis (6)	57,000	107,365	10,248	3,776	178,389
Robert D. Gershen	52,000	111,865	10,248		174,113
William R. Herrin, Jr. (7)	60,000	111,865	10,248		182,113
James R. Latimer	56,833	59,965	10,248		127,046
Bryant H. Patton	50,833	59,965	10,248		121,046
Steven J. Pully	57,333	63,090	10,248		130,671

(1) Amounts in this column reflect compensation expense recorded in our 2008 consolidated financial statements for each named director and include grants made in previous years for which compensation expense is required to be recognized in accordance with

128

SFAS No. 123(R). As of December 31, 2008, the outstanding stock awards held by each non-employee director was: (a) 6,000 restricted share units for each director granted under our Amended and Restated 2000 Stock Incentive Plan for Non-Employee Directors and (b) 21,309, 1,993 and 4,327 phantom shares accrued under our Stock and Deferral Plan for Non-Employee Directors for Messrs. Bumgarner and Gershen and Dr. Francis, respectively. The grant date fair value of restricted share unit awards made to all directors in 2008 was $14.99 per share as computed in accordance with SFAS No. 123(R). Please refer to Note 2(j) and 15 in the Part II, Item 8 of this Annual Report for a discussion of the assumptions used in computing the grant date fair value of stock based compensation awards. These amounts reflect our accounting expense for these awards and do not correspond to the actual value that might be realized by the named directors.

(2) Amounts in this column reflect compensation expense recorded in the 2008 consolidated financial statements for each named director and include grants made in previous years for which compensation expense is required to be recognized in accordance with SFAS No. 123(R). As of December 31, 2008, outstanding stock option awards for which compensation expenses was recognized included shares of common stock underlying options granted under our Amended and Restated 2000 Stock Incentive Plan for Non-Employee Directors in the following amounts: Mr. Bumgarner 34,875, Mr. Carlisle 24,875, Mr. Carter 34,875, Mr. Dawkins 20,875, Dr. Francis 14,875, Mr. Gershen 34,875, Mr. Herrin 14,875, Mr. Latimer 3,375, Mr. Patton 3,375 and Mr. Pully 3,375. The grant date fair value for each option award made in 2008 was $6.09. Please refer to footnotes 2(j) and 15 in our consolidated financial statements in Part II, Item 8 of this Annual Report for a discussion of the assumptions used in computing the grant date fair value of stock based compensation awards. These amounts reflect our accounting expense for these awards and do not correspond to the actual value that might be realized by the named directors.

(3) Mr. Bumgarner resigned from the Board in February 2009.

(4) Mr. Carter resigned from the Board in February 2009.

(5) Mr. Dawkins resigned from the Board in March, 2009.

(6) Mr. Francis resigned from the Board in February 2009. In 2009, Mr. Francis was reimbursed $3,776 for income tax liabilities incurred as a result of payment to him in 2008 of certain directors fees that he had previously elected to defer.

(7) Mr. Herrin resigned from the Board in February 2009.

Annual Retainers and Meeting Fees

Prior to our 2008 Annual Meeting of Stockholders held on May 29, 2008, non-employee directors were entitled to receive the following compensation:

- an annual retainer fee of $40,000 per year;
- meeting fees of $2,000 for each Board meeting attended;
- meeting fees of $1,500 for each committee meeting attended (even if held on the same date as a Board meeting);
- an additional retainer of $5,000 per year for each member of the Audit Committee, plus an additional retainer of $15,000 per year for the chairperson of the Audit Committee; and
- an additional retainer of $10,000 per year for the chairperson of each of the Compensation Committee and Nominating & Governance Committee.

Commencing with the 2008 Annual Meeting of Stockholders, the compensation for our non-employees directors is the same as discussed above with the exception that the annual retainer fee was reduced from $40,000 to $20,000. The Committee, based on data provided by Frederic W. Cook & Co, reduced the fee so that the total compensation received by our non-employee directors remains in line with the targeted 75th percentile of the 2008 Peer Group for total direct compensation of non-employee directors.

Meeting fees are paid in cash. Retainer fees are paid in shares of common stock (valued at fair market value); provided that a director may elect to receive up to 50% of such retainer fees in cash. Directors may defer all or a portion of their retainer and meeting fees. Our Stock and Deferral Plan for Non-Employee Directors governs the payment of retainer and meeting fees and the terms of any deferrals of such fees. The SFAS No. 123(R) charge for deferrals of retainer and meeting fees that are invested in phantom shares of our common stock is included in the stock awards column in the above table. Directors are also reimbursed for their reasonable expenses in connection with attending Board meetings and other company events.

Table of Contents

Equity Awards

Our Amended and Restated 2000 Stock Incentive Plan for Non-Employee Directors provides for grants of stock options and restricted share units to members of the Board who are not employees of our company or any of its subsidiaries. The size of any grants of stock options and restricted share units to non-employee directors, including to new directors, is determined annually, based on the analysis of Frederick W. Cook & Co., Inc., an independent compensation consultant. Based on this analysis, in April 2008, the Committee recommended, and the Board approved, the grant of 6,000 restricted share units to each non-employee director, and stock options with a binomial value of $20,000, on the date of the 2008 Annual Meeting of Stockholders. Pursuant to the terms of the plan, restricted share units and stock options become 100% vested on the first anniversary of the date of grant provided the eligible director continues as a director of throughout that one-year period. Prior to the first anniversary of the date of grant, an eligible director is vested in the pro rata number of restricted share units and stock options based on the number of days during that year that the eligible director served. The total number of shares of our common stock that may be issued under the plan is 500,000, subject to adjustment in the case of certain corporate transactions and events.

Table of Contents

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

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2008, with respect to compensation plans under which our equity securities are authorized for issuance.

Equity Compensation Plan Information

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (1) (a)	Weighted-average exercise price of outstanding options, warrants and rights (2) (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	2,054,021	$ 15.34	2,685,256
Equity compensation plans not approved by security holders			
Total	2,054,021	$ 15.34	2,685,256

(1) Comprised of 1,620,321 shares subject to issuance upon the exercise of options and 433,700 shares to be issued upon the lapsing of restrictions associated with restricted share units.

(2) Our restricted share units and performance shares do not have an exercise price; therefore, this only reflects the weighted-average option exercise price.
See Note 15, 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 plans.

Security Ownership of Certain Beneficial Owners and Management

The following table sets forth the beneficial ownership of our common stock as of July 27, 2009 by (1) each of our directors, (2) each of the executive officers named in the Summary Compensation Table, (3) all current directors and executive officers as a group and (4) each person known by us to own beneficially more than 5% of the outstanding shares of our common stock. Except as otherwise noted below, we are not aware of any agreements among our stockholders that relate to voting or investment of shares of our common stock.

	Common Stock Beneficially Owned (1)	
Name of Beneficial Owner	**Number of Shares**	**Percent of Class (2)**
Directors		
Jerry D. Carlisle (3)	50,562	*
Robert D. Gershen (4)	78,806	*
James R. Latimer, III (5)	10,324	*
Bryant H. Patton (5)	10,324	*
Steven J. Pully (5)	3,005,456	9.3%
Named Executive Officers		
Richard A. Bachmann (6)	1,935,934	6.0%
Thomas D. DeBrock (7)	90,409	*
Joseph T. Leary	500	*
Stephen D. Longon (7)	25,999	*
John H. Peper (8)	233,755	*
All current directors and executive officers as a group (11 persons) (9)	5,597,479	17.3%
Principal Holders		

Carlson Capital, L.P. and affiliates (10)	2,994,968	9.3%
Wexford Capital LLC and affiliates (11)	9,934,848	30.8%

* Less than 1%

(1) Beneficial ownership is determined in accordance with the SEC s rules and regulations and generally includes voting or investment power with respect to securities. Shares of our common stock subject to options and warrants currently exercisable, or exercisable within 60 days, are deemed outstanding for purposes of computing the percentage of shares beneficially owned by the person holding

such options, but are not deemed outstanding for computing the percentage of any other person. Restricted stock not yet vested is included in the total shares outstanding but excluded from both the total shares held by the beneficial holder and the total shares deemed outstanding for computing the percentage of the person holding such restricted stock. Except as indicated by footnote, and subject to community property laws where applicable, the persons named in the table have sole voting and investment power with respect to all shares of common stock shown as beneficially owned by them.

(2) Based on total shares outstanding of 32,286,310 at July 27, 2009. Also based on the number of shares owned and acquirable within 60 days of July 27, 2009.

(3) Includes 24,875 shares of common stock underlying options exercisable granted to Mr. Carlisle under our Amended and Restated 2000 Stock Incentive Plan for Non-Employee Directors. Includes 500 shares of common stock beneficially owned by Mr. Carlisle s wife of which Mr. Carlisle disclaims beneficial ownership.

(4) Includes 34,875 shares of common stock underlying options exercisable granted under our Amended and Restated 2000 Stock Incentive Plan for Non-Employee Directors to Mr. Gershen. Also includes 1,993 phantom shares accrued for Mr. Gershen under our Stock and Deferral Plan for Non-Employee Directors.

(5) Includes 3,375 shares of common stock underlying options exercisable granted under our Amended and Restated 2000 Stock Incentive Plan for Non-Employee Directors to each of Messrs. Latimer, Patton and Pully. Also includes 1,113 phantom shares accrued for Mr. Pully under our Stock and Deferral Plan for Non-Employee Directors and 2,994,968 shares of common stock held by Carlson Capital, L.P. (Carlson). Mr. Pully is an employee of Carlson and disclaims any beneficial ownership of shares of common stock held by Carlson.

(6) Includes 45,000 shares of common stock pledged to support obligations incurred in two separate transactions under Forward Purchase Agreements entered into with Citigroup. Mr. Bachmann retains voting rights with respect to these shares. The number of shares to be delivered commencing in August 2009 pursuant to such agreements will be based on the market price of the common stock and will not exceed 45,000 shares. Mr. Bachmann has the right to deliver cash instead of shares of common stock. Also includes (a) 642,088 shares of common stock underlying options (621,202 exercisable and 20,886 exercisable within 60 days of July 27, 2009) granted to Mr. Bachmann under our 2006 Long Term Stock Incentive Plan, (b) 4,174 shares of common stock beneficially owned by Mr. Bachmann and held in trust by our 401(k) Plan, (c) 2,148 shares beneficially owned by Mr. Bachmann s wife, and (d) 1,128,591 shares of common stock pledged in a margin account held by Mr. Bachmann.

(7) Includes 52,987 and 19,654 shares of common stock underlying options exercisable granted to Messrs. DeBrock and Longon, respectively, under our 2006 Long Term Stock Incentive Plan. Also includes 4,667 and 3,483 shares of common stock beneficially owned by Messrs. DeBrock and Longon, respectively, and held in trust by our 401(k) Plan. Also includes 28,644 shares of common stock pledged in a margin account held by Mr. DeBrock.

(8) Includes 215,846 shares of common stock underlying options (212,338 exercisable and 3,508 exercisable within 60 days of July 27, 2009) and 510 restricted share units exercisable within 60 days of July 27, 2009, granted to Mr. Peper under our 2006 Long Term Stock Incentive Plan. Also includes 5,606 shares of common stock beneficially owned by Mr. Peper and held in trust by our 401(k) Plan.

(9) Includes 1,103,203 shares of common stock underlying options (1,078,809 exercisable and 24,394 exercisable within 60 days of July 27, 2009) and 510 restricted share units exercisable within 60 days of July 27, 2009. See notes 3 through 8 above.

(10) Pursuant to a Schedule 13D/A filed with the SEC on March 9, 2009, Carlson, Double Black Diamond Offshore LDC (DBDO), Asgard Investment Corp. (Asgard), and Mr. Clint D. Carlson reported the following: Carlson, Asgard and Mr. Carlson each have the sole power to vote and the sole power to dispose of 2,994,968 shares of common stock and DBDO has the sole power to vote and the sole power to dispose of 2,028,446 shares of common stock. Carlson, as DBDO s investment manager, may, for purposes of Rule 13d-3 under the Exchange Act be deemed to beneficially own 2,028,446 shares of common stock held by DBDO, and beneficially own common stock held by other private investment funds and managed accounts (the Accounts). As Carlson s general partner, Asgard, may, for purposes of Rule 13d-3 under the Exchange Act, be deemed to own beneficially 2,994,968 shares of common stock. As the President of Asgard and the Chief Executive Officer of Carlson, Mr. Clint D. Carlson may, for purposes of Rule 13d-3 under the Exchange Act, be deemed to own beneficially 2,994,968 shares of common stock. Mr. Carlson, Asgard and Carlson disclaim any beneficial ownership of shares of common stock held by DBDO and the Accounts. The business address of the reporting persons is 2100 McKinney Avenue, Suite 1600, Dallas TX 75201.

(11) Pursuant to a Schedule 13D/A filed by Debello Investors LLC (Debello), Wexford Catalyst Investors LLC (Wexford Catalyst), Wexford Catalyst Trading Limited (Wexford Trading), Wexford Spectrum Trading Limited (Wexford Spectrum), Wexford Capital LLC (Wexford Capital), Mr. Charles E. Davidson and Mr. Joseph M. Jacobs with the SEC on March 5, 2009, Debello has shared voting and dispositive power over 15,709 shares, Wexford Catalyst has shared voting and dispositive power over 382,682 shares, Wexford Trading has shared voting and dispositive power over 405,000 shares, Wexford Spectrum has shared voting and dispositive power over 1,680,321 shares, and each of Wexford Capital, Mr. Charles E. Davidson and Mr. Joseph M. Jacobs have shared voting and dispositive power over 2,483,712 shares. Wexford Capital is the managing member or sub investment manager of each of Debello, Wexford Catalyst, Wexford Trading and Wexford Spectrum and by reason of its status as such may be deemed to own beneficially the interest in the shares of common stock of which such entities possess ownership. Each of Messrs. Davidson and Jacobs is a controlling person of Wexford Capital and may by reason of their status as such be deemed to own beneficially the interest in the shares of common

stock of which each of Wexford Capital, Debello, Wexford Catalyst, Wexford Trading and Wexford Spectrum possess ownership. Each of Wexford Capital and Messrs Davidson and Jacobs disclaims beneficial ownership of the shares of common stock held by Wexford Capital, Debello, Wexford Catalyst, Wexford Trading and Wexford Spectrum, respectively. The business address of the reporting persons is 411 West Putnam Avenue, Greenwich, CT 06830.

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

Transactions with Related Persons, Promoters and Certain Control Persons

Policies and Procedures

We currently do not have a written policy with respect to entering into transactions with members of management or affiliated companies. Although we have not adopted formal procedures for the review, approval or ratification of transactions with related persons, our Board of Directors reviews potential transactions with those parties we have identified as related parties prior to the consummation of the transaction, and we adhere to the general policy that such transactions should only be entered into if they are approved by our Board of Directors and in accordance with our Certificate of Incorporation, Bylaws and Delaware law.

Transactions

Since the beginning of the fiscal year ended January 31, 2008, we have not participated in (or proposed to participate in) any transactions with related persons as defined in Item 404(a) of Regulation S-K.

Director Independence

Under our Corporate Governance Guidelines, a majority of the Board must be comprised of directors who are independent under the listing standards of the NYSE. No director will be deemed to be independent unless the Board affirmatively determines that the director has no material relationship with our company, either directly or as an officer, stockholder or partner of an organization that has a relationship with us. In its review of director independence, the Board considers all relevant facts and circumstances, including without limitation, all commercial, banking, consulting, legal, accounting, charitable or other business relationships any director may have with us. The Board has adopted categorical standards to assist it in making determinations of independence for directors, a copy of which was filed as Annex I to our proxy statement for the 2008 Annual Meeting of Stockholders as filed with the SEC in April 2008.

Under the standards adopted by the Board, it has determined that each of Messrs. Carlisle, Gershen, Latimer, Patton and Pully is independent.

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

General

The following table sets forth the amount of audit fees, audit-related fees and tax fees billed or expected to be billed by KPMG LLP, our independent registered public accounting firm, for the fiscal years ended December 31, 2008 and December 31, 2007:

	2008	2007
Audit fees (1)	$ 845,000	$ 688,850
Audit-related fees (2)		
Tax fees (3)		
All other fees (4)		
Total Fees	$ 845,000	$ 688,850

(1) Represents amount incurred through July 15, 2009. Audit fees for 2008 consisted only of integrated audit services. Audit fees for 2007 consisted of: (a) integrated audit services $550,000 and (b) registration statements $138,850.

Table of Contents

(2) There were no audit-related fees (including expenses) with respect to fiscal 2008 and fiscal 2007.

(3) There were no tax fees (including expenses) with respect to fiscal 2008 and fiscal 2007.

(4) There were no other fees (including expenses) with respect to fiscal 2008 and fiscal 2007.

The Audit Committee believes that the foregoing expenditures are compatible with maintaining the independence of our public accountants. The Audit Committee pre-approved all such audit and non-audit services by our independent registered public accountants during 2007 and 2008 pursuant to the policies and procedures discussed below.

Pre-Approval Policies and Procedures

The Audit Committee has adopted procedures for pre-approving all audit and permissible non-audit services provided by the independent registered public accountants. Under such procedures, the Audit Committee will annually review and pre-approve the audit, review and attest services to be provided during the next audit cycle by the independent registered public accountants and may annually review and pre-approve permitted non-audit services to be provided during the next audit cycle by the independent registered public accountants. To the extent practicable, the Audit Committee will also review and approve a budget for such services. Services proposed to be provided by the independent registered public accountants that have not been pre-approved during the annual review and the fees for such proposed services must be pre-approved by the Audit Committee or its designated subcommittee. Additionally, fees for previously approved services that are expected to exceed the previously approved budget must also be pre-approved by the Audit Committee or its designated subcommittee. All requests or applications for the independent registered public accountants to provide services to our company must be submitted to the Audit Committee or its designated subcommittee by the Chief Financial Officer or Controller and must address whether, in his or her view, the request or application is consistent with applicable laws, rules and regulations relating to auditor independence.

Table of Contents

PART IV

Item 15. ***Exhibits, 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 Firm s Report

Consolidated Balance Sheets as of December 31, 2008 and 2007

Consolidated Statements of Operations for the years ended December 31, 2008, 2007 and 2006

Consolidated Statements of Changes in Stockholders Equity for the years ended December 31, 2008, 2007 and 2006

Consolidated Statements of Cash Flows for the years ended December 31, 2008, 2007 and 2006

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*

The exhibits marked with the asterisk symbol (*) are filed or furnished (in the case of Exhibits 32.1 and 32.2) with this Annual Report. 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.

We have not filed with this Annual Report copies of the instruments defining rights of all holders of the long-term debt of us and our consolidated subsidiaries based upon the exception set forth in Item 601(b)(4)(iii)(A) of Regulation S-K. Copies of such instruments will be furnished to the SEC upon request.

Exhibit Number	Description
3.1	Restated Certificate of Incorporation of Energy Partners, Ltd. dated as of November 16, 1999 (incorporated by reference to Exhibit 3.1 to Energy Partners, Ltd. s Form S-1 (File No. 333-42876)).
3.2	Amendment to Restated Certificate of Incorporation of Energy Partners, Ltd. dated as of September 15, 2000 (incorporated by reference to Exhibit 3.2 to Energy Partners, Ltd. s Form S-1 (File No. 333-42876)).
3.3	

	Certificate of Amendment of the Restated Certificate of Incorporation of Energy Partners, Ltd. dated as of May 5, 2006 (incorporated by reference to Exhibit 3.6 to Energy Partners, Ltd. s Form 10-Q filed May 9, 2006 (File No. 001-16179)).
3.4	Certificate of Elimination of the Series A Convertible Preferred Stock, Series B Convertible Preferred Stock and Series C Preferred Stock of Energy Partners, Ltd. (incorporated by reference to Exhibit 4.2 of Energy Partners, Ltd. s Form 8-K filed January 22, 2002 (File No. 001-16179)).

Table of Contents

Exhibit Number	Description
3.5	Certificate of Elimination of the Series D Exchangeable Convertible Preferred Stock of Energy Partners, Ltd. (incorporated by reference to Exhibit 3.4 to Energy Partners, Ltd. s Form 10-K filed February 27, 2006 (File No. 001-16179)).
3.6	Amended and Restated Bylaws of Energy Partners, Ltd. (incorporated by reference to Exhibit 3.5 of Energy Partners, Ltd. s Form 10-K filed March 3, 2008 (File No. 001-16179)).
*4.1	Indenture dated as of August 5, 2003 between Energy Partners, Ltd., as Issuer, and Wells Fargo Bank, N.A., as Trustee.
4.2	Indenture dated as of April 23, 2007 between Energy Partners, Ltd., as Issuer, and Wells Fargo Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.1 to Energy Partners, Ltd. s Form 8-K filed on April 26, 2007 (File No. 011-16179)).
10.1	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 July 31, 2009 (incorporated by reference to Exhibit 99.1 to Energy Partners, Ltd. s Form 8-K filed on August 4, 2009 (File No. 001-16179)).
10.2	Plan of Support and Lock-Up Agreement dated as of April 30, 2009 between Energy Partners, Ltd., and the holders of claims against Energy Partners, Ltd. signatory thereto (incorporated by reference to Exhibit 10.1 to Energy Partners, Ltd. s Form 8-K filed on May 5, 2009 (File No. 001-16179)).
10.3	Credit Agreement dated as of April 23, 2007 among Energy Partners, Ltd., Bank of America, N.A., as Administrative Agent, L/C Issuer and Collateral Agent, JPMorgan Chase Bank, N.A. and BNP Paribas, as Co-Syndication Agents, The Bank of Nova Scotia and BMO Capital Markets Financing, Inc., as Co-Documentation Agents, and the other lenders party thereto (incorporated by reference to Exhibit 10.2 to Energy Partners, Ltd. s Form 8-K filed on April 26, 2007 (File No. 001-16179)).
*10.4	Letter Agreement dated as of April 3, 2009 among Energy Partners, Ltd., Bank of America, N.A., as Administrative Agent, Lender, Collateral Agent and L/C Issuer, and the other loan parties and lenders party thereto.
10.5	Letter Agreement dated as of April 14, 2009 among Energy Partners, Ltd., Bank of America, N.A., as Administrative Agent, Lender, Collateral Agent and L/C Issuer, and the other loan parties and lenders party thereto (incorporated by reference to Exhibit 10.1 to Energy Partners, Ltd. s Form 8-K filed on April 14, 2009 (File No. 001-16179)).
*10.6	Term sheet with the United States Department of the Interior, Minerals Management Service dated April 30, 2009.
10.7	Letter Agreement, dated as of April 1, 2008 among Energy Partners, Ltd., Double Black Diamond Offshore LDC, Carlson Capital, L.P., Asgard Investment Corp., James, R. Latimer, III, Bryant H. Patton, Steven J. Pully and Clint D. Carlson (incorporated by reference to Exhibit 10.1 to Energy Partners, Ltd. s Form 8-K filed on April 2, 2008 (File No. 001-16179)).
10.8	Form of Indemnity Agreement (incorporated by reference to Exhibit 10.1 to Energy Partners, Ltd. s Form 8-K filed on September 14, 2006 (File No. 001-16179)).
10.9	Amended and Restated 2000 Stock Incentive Plan for Non-Employee Directors effective as of May 12, 2005 (incorporated by reference to Annex B to Energy Partners, Ltd. s proxy statement on Schedule 14A filed April 4, 2005 (File No. 001-16179)).
10.10	First Amendment to the Amended and Restated 2000 Stock Incentive Plan for Non-Employee Directors dated November 13, 2008 (incorporated by reference to Exhibit 10.4 to Energy Partners, Ltd. s Form 8-K filed November 14, 2008 (File No. 001-16179)).

Table of Contents

Exhibit Number	Description
10.11	Form of Restricted Share Unit Agreement under the Amended and Restated 2000 Stock Option Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.2 of Energy Partners, Ltd. s Form 10-Q filed August 5, 2008 (File No. 001-16179)).
10.12	Energy Partners, Ltd. Stock and Deferral Plan for Non-Employee Directors, as amended and restated effective as of July 17, 2003 (incorporated by reference to Exhibit 10.1 to Energy Partners, Ltd. s Form 10-Q filed on August 5, 2008 (File No. 001-16179)).
10.13	First Amendment to the Energy Partners, Ltd. Stock and Deferral Plan for Non-Employee Directors dated as of November 13, 2008 (incorporated by reference to Exhibit 10.5 to Energy Partners, Ltd. s Form 8-K filed November 14, 2008 (File No. 001-16179)).
*10.14	Summary of Non-Employee Director Compensation as of July 2009.
10.15	Amended and Restated 2000 Long Term Stock Incentive Plan effective as of September 12, 2000 (incorporated by reference to Exhibit 10.2 of Energy Partners, Ltd. s Form 10-K filed March 15, 2002 (File No. 001-16179)).
10.16	First Amendment to Amended and Restated 2000 Long Term Stock Incentive Plan effective as of May 13, 2004 (incorporated by reference to Exhibit 10.2 of Energy Partners, Ltd. s Form 8-K filed November 14, 2008 (File No. 001-16179)).
10.17	Form of Nonqualified Stock Option Agreement under the Amended and Restated 2000 Long Term Stock Incentive Plan (incorporated by reference to Exhibit 10.3 of Energy Partners, Ltd. s Form 10-Q filed August 5, 2004 (File No. 001-16179)).
10.18	Form of Restricted Share Unit Agreement under the Amended and Restated 2000 Long Term Stock Incentive Plan (incorporated by reference to Exhibit 10.4 of Energy Partners, Ltd. s Form 10-Q filed August 5, 2004 (File No. 001-16179)).
10.19	Form of Performance Share Agreement under the Amended and Restated 2000 Long Term Stock Incentive Plan (incorporated by reference to Exhibit 10.3 of Energy Partners, Ltd. s Form 8-K filed March 30, 2005 (File No. 001-16179)).
10.20	2006 Long Term Stock Incentive Plan effective as of May 4, 2006 (incorporated by reference to Annex C to Energy Partners, Ltd. s proxy statement on Schedule 14A filed April 5, 2006 (File No. 001-16179)).
10.21	First Amendment to the 2006 Long Term Stock Incentive Plan dated November 13, 2008 (incorporated by reference to Exhibit 10.3 of Energy Partners, Ltd. s Form 8-K filed November 14, 2008 (File No. 001-16179)).
10.22	Form of 2006 Long Term Stock Incentive Plan Cash-Settled Restricted Share Unit Agreement (incorporated by reference to Exhibit 10.1 to Energy Partners, Ltd. s Form 8-K filed on June 5, 2007 (File No. 001-16179)).
10.23	Form of 2006 Long Term Stock Incentive Plan Nonqualified Stock Option Agreement (incorporated by reference to Exhibit 10.5 to Energy Partners, Ltd. s Form 10-Q filed on May 3, 2007 (File No. 001-16179)).
10.24	Form of 2006 Long Term Stock Incentive Plan Restricted Share Unit Agreement (incorporated by reference to Exhibit 10.6 to Energy Partners, Ltd. s Form 10-Q filed on May 3, 2007 (File No. 001-16179)).
10.25	Form of 2006 Long Term Stock Incentive Plan Cash-Settled Restricted Share Appreciation Right Agreement (incorporated by reference to Exhibit 10.1 to Energy Partners, Ltd. s Form 10-Q filed on May 8, 2008 (File No. 001-16179)).

Table of Contents

Exhibit Number	Description
10.26	Amendment to Restricted Share Unit Agreements and Cash-Settled Restricted Share Unit Agreements under the 2006 Long Term Stock Incentive Plan or the Amended and Restated 2000 Long Term Stock Incentive Plan (incorporated by reference to Exhibit 10.6 to Energy Partners, Ltd. s Form 8-K filed on November 14, 2008 (File No. 001-16179)).
10.27	Change of Control Severance Plan effective as of March 24, 2005 (incorporated by reference to Exhibit 10.2 of Energy Partners, Ltd. s Form 8-K filed March 30, 2005 (File No. 001-16179)).
10.28	First Amendment to Change of Control Severance Plan effective as of September 13, 2006 (incorporated by reference to Exhibit 10.3 to Energy Partners, Ltd. s Form 8-K filed on September 14, 2006 (File No. 001-16179)).
10.29	Second Amendment to Change of Control Severance Plan effective as of April 16, 2008 (incorporated by reference to Exhibit 10.3 to Energy Partners, Ltd. s Form 10-Q filed on May 8, 2008 (File No. 001-16179)).
10.30	Third Amendment to Change of Control Severance Plan dated November 13, 2008 (incorporated by reference to Exhibit 10.2 of Energy Partners, Ltd. s Form 8-K filed November 14, 2008 (File No. 001-16179)).
10.31	Form of Change of Control Severance Agreement (incorporated by reference to Exhibit 10.1 of Energy Partners, Ltd. s Form 8-K filed March 30, 2005 (File No. 001-16179)).
10.32	Form of First Amendment to Change of Control Severance Agreement (incorporated by reference to Exhibit 10.2 to Energy Partners, Ltd. s Form 8-K filed on September 14, 2006 (File No. 001-16179)).
10.33	Form of Second Amendment to Change of Control Severance Agreement (incorporated by reference to Exhibit 10.13 of Energy Partners, Ltd. s Form 10-K filed March 3, 2008 (File No. 001-16179)).
10.34	Form of Third Amendment to Change of Control Severance Agreement (incorporated by reference to Exhibit 10.7 of Energy Partners, Ltd. s Form 8-K filed November 14, 2008 (File No. 001-16179)).
*10.35	Form of Senior Management Settlement Agreement.
*10.36	Form of Omnibus Settlement Agreement.
10.37	Description of the Fiscal 2007 Annual Incentive Bonus Program for Executive Officers of Energy Partners, Ltd. (incorporated by reference to Energy Partners, Ltd. s proxy statement on Schedule 14A filed on April 28, 2008 (File No. 001-16179)).
10.38	Description of the Fiscal 2008 Annual Incentive Bonus Program for Executive Officers of Energy Partners, Ltd. (incorporated by reference to Part III, Item 11 of Energy Partners, Ltd. s Form 10-K filed on August 4, 2009 (File No. 001-16179)).
10.39	General Release between T. Rodney Dykes and Energy Partners, Ltd. effective as of March 31, 2008 (incorporated by reference to Exhibit 10.25 to Energy Partners, Ltd. s Form 10-K filed on March 3, 2008 (File No. 001-16179)).
*10.40	Letter Agreement between Thomas DeBrock and Energy Partners, Ltd. dated November 29, 2007.
10.41	Amendment to Letter Agreement between Thomas DeBrock and Energy Partners, Ltd. dated November 12, 2008 (incorporated by reference to Exhibit 10.8 to Energy Partners, Ltd. s Form 8-K filed on November 14, 2008 (File No. 001-16179)).
*10.42	Senior Management Settlement Agreement dated as of June 30, 2009 by and between Energy Partners, Ltd. and Thomas DeBrock.

Table of Contents

Exhibit Number	Description
*10.43	Amendment to Nonqualified Stock Options granted to Phillip A. Gobe dated as of August 21, 2007.
*10.44	Amendment to Restricted Share Unit Agreements granted to Phillip A. Gobe dated as of August 21, 2007.
*10.45	Amendment to Cash-Settled Restricted Share Unit Agreement granted to Phillip A. Gobe dated as of August 21, 2007.
*10.46	Amendment to Restricted Share Unit Agreements granted to Phillip A. Gobe dated as of November 19, 2008.
*10.47	Amendment to Cash Settled Restricted Share Unit Agreement granted to Phillip A. Gobe dated as of November 19, 2008.
*10.48	Offer Letter to Joseph T. Leary dated August 15, 2007.
*10.49	Offer Letter to Stephen D. Longon dated June 11, 2007.
*10.50	Settlement Agreement dated as of June 23, 2009 by and between Energy Partners, Ltd. and Stephen D. Longon.
*10.51	Settlement Agreement dated as of June 23, 2009 by and between Energy Partners, Ltd. and John H. Peper.
*21.1	Subsidiaries of Energy Partners, Ltd.
*23.1	Consent of KPMG LLP.
*23.2	Consent of Netherland, Sewell & Associates, Inc.
*23.3	Consent of Ryder Scott Company, L.P.
*31.1	Certification of Principal Executive Officer of Energy Partners, Ltd. pursuant to Section 302 of the Sarbanes Oxley Act of 2002.
*31.2	Certification of Principal Financial Officer of Energy Partners, Ltd. pursuant to Section 302 of the Sarbanes Oxley Act of 2002.
*32.1	Section 1350 Certification of Principal Executive Officer of Energy Partners, Ltd. pursuant to Section 906 of the Sarbanes Oxley Act of 2002.
*32.2	Section 1350 Certification of Principal Financial Officer of Energy Partners, Ltd. pursuant to Section 906 of the Sarbanes Oxley Act of 2002.

Table of Contents

GLOSSARY OF OIL AND NATURAL GAS TERMS

Bbl 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 Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

Bcf One billion cubic feet.

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

completion 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.

EBITDAX Net income (loss) before interest expense, income taxes, depreciation, depletion and amortization, exploration expenditures and cumulative effect of change in accounting principle.

Loe Lease operating expenditures.

Mbbls One thousand barrels of oil or other liquid hydrocarbons.

Mboe One thousand barrels of oil equivalent.

Mcf One thousand cubic feet of natural gas.

Mmbbls One million barrels of oil or other liquid hydrocarbons.

Mmboe One million barrels of oil equivalent.

Mmbtu One million British Thermal Units.

Mmcf One million cubic feet of natural gas.

plugging and abandonment Refers to 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 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 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 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.

Table of Contents

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: August 4, 2009

ENERGY PARTNERS, LTD.

By: /s/ ALAN D. BELL
Alan D. Bell

Chief Restructuring Officer (Principal 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/ ALAN D. BELL	Chief Restructuring Officer	August 4, 2009
Alan D. Bell	(Principal Executive Officer)	
/s/ TIFFANY J. THOM	Vice President, Treasurer and Investor Relations	August 4, 2009
Tiffany J. Thom	(Principal Financial Officer)	
/s/ DAVID P. CEDRO	Vice President, Controller	August 4, 2009
David P. Cedro	(Principal Accounting Officer)	
/s/ JERRY D. CARLISLE	Director	August 4, 2009
Jerry D. Carlisle		
/s/ ROBERT D. GERSHEN	Director	August 4, 2009
Robert D. Gershen		
/s/ JAMES R. LATIMER	Director	August 4, 2009
James R. Latimer		
/s/ BRYANT H. PATTON	Director	August 4, 2009
Bryant H. Patton		
/s/ STEVEN J. PULLY	Director	August 4, 2009
Steven J. Pully		

Table of Contents

INDEX TO EXHIBITS

The exhibits marked with the asterisk symbol (*) are filed or furnished (in the case of Exhibits 32.1 and 32.2) with this Annual Report. 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.

We have not filed with this Annual Report copies of the instruments defining rights of all holders of the long-term debt of us and our consolidated subsidiaries based upon the exception set forth in Item 601(b)(4)(iii)(A) of Regulation S-K. Copies of such instruments will be furnished to the SEC upon request.

Exhibit Number	Description
3.1	Restated Certificate of Incorporation of Energy Partners, Ltd. dated as of November 16, 1999 (incorporated by reference to Exhibit 3.1 to Energy Partners, Ltd. s Form S-1 (File No. 333-42876)).
3.2	Amendment to Restated Certificate of Incorporation of Energy Partners, Ltd. dated as of September 15, 2000 (incorporated by reference to Exhibit 3.2 to Energy Partners, Ltd. s Form S-1 (File No. 333-42876)).
3.3	Certificate of Amendment of the Restated Certificate of Incorporation of Energy Partners, Ltd. dated as of May 5, 2006 (incorporated by reference to Exhibit 3.6 to Energy Partners, Ltd. s Form 10-Q filed May 9, 2006 (File No. 001-16179)).
3.4	Certificate of Elimination of the Series A Convertible Preferred Stock, Series B Convertible Preferred Stock and Series C Preferred Stock of Energy Partners, Ltd. (incorporated by reference to Exhibit 4.2 of Energy Partners, Ltd. s Form 8-K filed January 22, 2002 (File No. 001-16179)).
3.5	Certificate of Elimination of the Series D Exchangeable Convertible Preferred Stock of Energy Partners, Ltd. (incorporated by reference to Exhibit 3.4 to Energy Partners, Ltd. s Form 10-K filed February 27, 2006 (File No. 001-16179)).
3.6	Amended and Restated Bylaws of Energy Partners, Ltd. (incorporated by reference to Exhibit 3.5 of Energy Partners, Ltd. s Form 10-K filed March 3, 2008 (File No. 001-16179)).
*4.1	Indenture dated as of August 5, 2003 between Energy Partners, Ltd., as Issuer, and Wells Fargo Bank, N.A., as Trustee.
4.2	Indenture dated as of April 23, 2007 between Energy Partners, Ltd., as Issuer, and Wells Fargo Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.1 to Energy Partners, Ltd. s Form 8-K filed on April 26, 2007 (File No. 011-16179)).
10.1	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 July 31, 2009 (incorporated by reference to Exhibit 99.1 to Energy Partners, Ltd. s Form 8-K filed on August 4, 2009 (File No. 001-16179)).
10.2	Plan of Support and Lock-Up Agreement dated as of April 30, 2009 between Energy Partners, Ltd., and the holders of claims against Energy Partners, Ltd. signatory thereto (incorporated by reference to Exhibit 10.1 to Energy Partners, Ltd. s Form 8-K filed on May 5, 2009 (File No. 001-16179)).
10.3	Credit Agreement dated as of April 23, 2007 among Energy Partners, Ltd., Bank of America, N.A., as Administrative Agent, L/C Issuer and Collateral Agent, JPMorgan Chase Bank, N.A. and BNP Paribas, as Co-Syndication Agents, The Bank of Nova Scotia and BMO Capital Markets Financing, Inc., as Co-Documentation Agents, and the other lenders party thereto (incorporated by reference to Exhibit 10.2 to Energy Partners, Ltd. s Form 8-K filed on April 26, 2007 (File No. 001-16179)).

Exhibit Number	Description
*10.4	Letter Agreement dated as of April 3, 2009 among Energy Partners, Ltd., Bank of America, N.A., as Administrative Agent, Lender, Collateral Agent and L/C Issuer, and the other loan parties and lenders party thereto.
10.5	Letter Agreement dated as of April 14, 2009 among Energy Partners, Ltd., Bank of America, N.A., as Administrative Agent, Lender, Collateral Agent and L/C Issuer, and the other loan parties and lenders party thereto (incorporated by reference to Exhibit 10.1 to Energy Partners, Ltd. s Form 8-K filed on April 14, 2009 (File No. 001-16179)).
*10.6	Term sheet with the United States Department of the Interior, Minerals Management Service dated April 30, 2009.
10.7	Letter Agreement, dated as of April 1, 2008 among Energy Partners, Ltd., Double Black Diamond Offshore LDC, Carlson Capital, L.P., Asgard Investment Corp., James, R. Latimer, III, Bryant H. Patton, Steven J. Pully and Clint D. Carlson (incorporated by reference to Exhibit 10.1 to Energy Partners, Ltd. s Form 8-K filed on April 2, 2008 (File No. 001-16179)).
10.8	Form of Indemnity Agreement (incorporated by reference to Exhibit 10.1 to Energy Partners, Ltd. s Form 8-K filed on September 14, 2006 (File No. 001-16179)).
10.9	Amended and Restated 2000 Stock Incentive Plan for Non-Employee Directors effective as of May 12, 2005 (incorporated by reference to Annex B to Energy Partners, Ltd. s proxy statement on Schedule 14A filed April 4, 2005 (File No. 001-16179)).
10.10	First Amendment to the Amended and Restated 2000 Stock Incentive Plan for Non-Employee Directors dated November 13, 2008 (incorporated by reference to Exhibit 10.4 to Energy Partners, Ltd. s Form 8-K filed November 14, 2008 (File No. 001-16179)).
10.11	Form of Restricted Share Unit Agreement under the Amended and Restated 2000 Stock Option Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.2 of Energy Partners, Ltd. s Form 10-Q filed August 5, 2008 (File No. 001-16179)).
10.12	Energy Partners, Ltd. Stock and Deferral Plan for Non-Employee Directors, as amended and restated effective as of July 17, 2003 (incorporated by reference to Exhibit 10.1 to Energy Partners, Ltd. s Form 10-Q filed on August 5, 2008 (File No. 001-16179)).
10.13	First Amendment to the Energy Partners, Ltd. Stock and Deferral Plan for Non-Employee Directors dated as of November 13, 2008 (incorporated by reference to Exhibit 10.5 to Energy Partners, Ltd. s Form 8-K filed November 14, 2008 (File No. 001-16179)).
*10.14	Summary of Non-Employee Director Compensation as of July 2009.
10.15	Amended and Restated 2000 Long Term Stock Incentive Plan effective as of September 12, 2000 (incorporated by reference to Exhibit 10.2 of Energy Partners, Ltd. s Form 10-K filed March 15, 2002 (File No. 001-16179)).
10.16	First Amendment to Amended and Restated 2000 Long Term Stock Incentive Plan effective as of May 13, 2004 (incorporated by reference to Exhibit 10.2 of Energy Partners, Ltd. s Form 8-K filed November 14, 2008 (File No. 001-16179)).
10.17	Form of Nonqualified Stock Option Agreement under the Amended and Restated 2000 Long Term Stock Incentive Plan (incorporated by reference to Exhibit 10.3 of Energy Partners, Ltd. s Form 10-Q filed August 5, 2004 (File No. 001-16179)).
10.18	Form of Restricted Share Unit Agreement under the Amended and Restated 2000 Long Term Stock Incentive Plan (incorporated by reference to Exhibit 10.4 of Energy Partners, Ltd. s Form 10-Q filed August 5, 2004 (File No. 001-16179)).

Table of Contents

Exhibit Number	Description
10.19	Form of Performance Share Agreement under the Amended and Restated 2000 Long Term Stock Incentive Plan (incorporated by reference to Exhibit 10.3 of Energy Partners, Ltd. s Form 8-K filed March 30, 2005 (File No. 001-16179)).
10.20	2006 Long Term Stock Incentive Plan effective as of May 4, 2006 (incorporated by reference to Annex C to Energy Partners, Ltd. s proxy statement on Schedule 14A filed April 5, 2006 (File No. 001-16179)).
10.21	First Amendment to the 2006 Long Term Stock Incentive Plan dated November 13, 2008 (incorporated by reference to Exhibit 10.3 of Energy Partners, Ltd. s Form 8-K filed November 14, 2008 (File No. 001-16179)).
10.22	Form of 2006 Long Term Stock Incentive Plan Cash-Settled Restricted Share Unit Agreement (incorporated by reference to Exhibit 10.1 to Energy Partners, Ltd. s Form 8-K filed on June 5, 2007 (File No. 001-16179)).
10.23	Form of 2006 Long Term Stock Incentive Plan Nonqualified Stock Option Agreement (incorporated by reference to Exhibit 10.5 to Energy Partners, Ltd. s Form 10-Q filed on May 3, 2007 (File No. 001-16179)).
10.24	Form of 2006 Long Term Stock Incentive Plan Restricted Share Unit Agreement (incorporated by reference to Exhibit 10.6 to Energy Partners, Ltd. s Form 10-Q filed on May 3, 2007 (File No. 001-16179)).
10.25	Form of 2006 Long Term Stock Incentive Plan Cash-Settled Restricted Share Appreciation Right Agreement (incorporated by reference to Exhibit 10.1 to Energy Partners, Ltd. s Form 10-Q filed on May 8, 2008 (File No. 001-16179)).
10.26	Amendment to Restricted Share Unit Agreements and Cash-Settled Restricted Share Unit Agreements under the 2006 Long Term Stock Incentive Plan or the Amended and Restated 2000 Long Term Stock Incentive Plan (incorporated by reference to Exhibit 10.6 to Energy Partners, Ltd. s Form 8-K filed on November 14, 2008 (File No. 001-16179)).
10.27	Change of Control Severance Plan effective as of March 24, 2005 (incorporated by reference to Exhibit 10.2 of Energy Partners, Ltd. s Form 8-K filed March 30, 2005 (File No. 001-16179)).
10.28	First Amendment to Change of Control Severance Plan effective as of September 13, 2006 (incorporated by reference to Exhibit 10.3 to Energy Partners, Ltd. s Form 8-K filed on September 14, 2006 (File No. 001-16179)).
10.29	Second Amendment to Change of Control Severance Plan effective as of April 16, 2008 (incorporated by reference to Exhibit 10.3 to Energy Partners, Ltd. s Form 10-Q filed on May 8, 2008 (File No. 001-16179)).
10.30	Third Amendment to Change of Control Severance Plan dated November 13, 2008 (incorporated by reference to Exhibit 10.2 of Energy Partners, Ltd. s Form 8-K filed November 14, 2008 (File No. 001-16179)).
10.31	Form of Change of Control Severance Agreement (incorporated by reference to Exhibit 10.1 of Energy Partners, Ltd. s Form 8-K filed March 30, 2005 (File No. 001-16179)).
10.32	Form of First Amendment to Change of Control Severance Agreement (incorporated by reference to Exhibit 10.2 to Energy Partners, Ltd. s Form 8-K filed on September 14, 2006 (File No. 001-16179)).
10.33	Form of Second Amendment to Change of Control Severance Agreement (incorporated by reference to Exhibit 10.13 of Energy Partners, Ltd. s Form 10-K filed March 3, 2008 (File No. 001-16179)).

Table of Contents

Exhibit Number	Description
10.34	Form of Third Amendment to Change of Control Severance Agreement (incorporated by reference to Exhibit 10.7 of Energy Partners, Ltd. s Form 8-K filed November 14, 2008 (File No. 001-16179)).
*10.35	Form of Senior Management Settlement Agreement.
*10.36	Form of Omnibus Settlement Agreement.
10.37	Description of the Fiscal 2007 Annual Incentive Bonus Program for Executive Officers of Energy Partners, Ltd. (incorporated by reference to Energy Partners, Ltd. s proxy statement on Schedule 14A filed on April 28, 2008 (File No. 001-16179)).
10.38	Description of the Fiscal 2008 Annual Incentive Bonus Program for Executive Officers of Energy Partners, Ltd. (incorporated by reference to Part III, Item 11 of Energy Partners, Ltd. s Form 10-K filed on August 4, 2009 (File No. 001-16179)).
10.39	General Release between T. Rodney Dykes and Energy Partners, Ltd. effective as of March 31, 2008 (incorporated by reference to Exhibit 10.25 to Energy Partners, Ltd. s Form 10-K filed on March 3, 2008 (File No. 001-16179)).
*10.40	Letter Agreement between Thomas DeBrock and Energy Partners, Ltd. dated November 29, 2007.
10.41	Amendment to Letter Agreement between Thomas DeBrock and Energy Partners, Ltd. dated November 12, 2008 (incorporated by reference to Exhibit 10.8 to Energy Partners, Ltd. s Form 8-K filed on November 14, 2008 (File No. 001-16179)).
*10.42	Senior Management Settlement Agreement dated as of June 30, 2009 by and between Energy Partners, Ltd. and Thomas DeBrock.
*10.43	Amendment to Nonqualified Stock Options granted to Phillip A. Gobe dated as of August 21, 2007.
*10.44	Amendment to Restricted Share Unit Agreements granted to Phillip A. Gobe dated as of August 21, 2007.
*10.45	Amendment to Cash-Settled Restricted Share Unit Agreement granted to Phillip A. Gobe dated as of August 21, 2007.
*10.46	Amendment to Restricted Share Unit Agreements granted to Phillip A. Gobe dated as of November 19, 2008.
*10.47	Amendment to Cash Settled Restricted Share Unit Agreement granted to Phillip A. Gobe dated as of November 19, 2008.
*10.48	Offer Letter to Joseph T. Leary dated August 15, 2007.
*10.49	Offer Letter to Stephen D. Longon dated June 11, 2007.
*10.50	Settlement Agreement dated as of June 23, 2009 by and between Energy Partners, Ltd. and Stephen D. Longon.
*10.51	Settlement Agreement dated as of June 23, 2009 by and between Energy Partners, Ltd. and John H. Peper.
*21.1	Subsidiaries of Energy Partners, Ltd.
*23.1	Consent of KPMG LLP.

Table of Contents

Exhibit Number	Description
*23.2	Consent of Netherland, Sewell & Associates, Inc.
*23.3	Consent of Ryder Scott Company, L.P.
*31.1	Certification of Principal Executive Officer of Energy Partners, Ltd. pursuant to Section 302 of the Sarbanes Oxley Act of 2002.
*31.2	Certification of Principal Financial Officer of Energy Partners, Ltd. pursuant to Section 302 of the Sarbanes Oxley Act of 2002.
*32.1	Section 1350 Certification of Principal Executive Officer of Energy Partners, Ltd. pursuant to Section 906 of the Sarbanes Oxley Act of 2002.
*32.2	Section 1350 Certification of Principal Financial Officer of Energy Partners, Ltd. pursuant to Section 906 of the Sarbanes Oxley Act of 2002.