ENERGY PARTNERS LTD
Form 10-K
August 05, 2009
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 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	**(I.R.S. Employer**
incorporation or organization)	**Identification No.)**
201 St. Charles Avenue, Suite 3400	
New Orleans, Louisiana	**70170**
(Address of principal executive offices)	**(Zip Code)**

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

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

PART I

Item 1. *Business*

Overview

Energy Partners, Ltd. (referred to herein as   we,   our,   us   or the   Company) was incorporated as a Delaware corporation in January 1998 and operates 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;

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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 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.

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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.

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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.

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	As of December 31, 2008	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:

	Years Ended December 31, 2008	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.

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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.

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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

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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.

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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.

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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.

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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.

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.

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.

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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 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.

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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

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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.

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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.

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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.

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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

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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;

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- 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.

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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, 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.

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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.

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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.

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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.

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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

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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.

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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.

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

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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.

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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.

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***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;

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.

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.

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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,	