ENERGY PARTNERS LTD
Form 10-K
February 27, 2006

Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2005

or

o **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 *(State or other jurisdiction of incorporation or organization)*	**72-1409562** *(I.R.S. Employer Identification No.)*
201 St. Charles Avenue, Suite 3400 **New Orleans, Louisiana** *(Address of principal executive offices)*	**70170** *(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	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by a check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No o

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 o No þ

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 þ No o

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. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check One)

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Act). Yes o No þ

The aggregate market value of the common stock held by non-affiliates of the registrant at June 30, 2005 based on the closing price of such stock as quoted on the New York Stock Exchange on that date was $877,972,594.

As of February 22, 2006 there were 38,017,698 shares of the registrant s common stock, par value $0.01 per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the registrant s definitive proxy statement for its 2006 Annual Meeting of Stockholders have been incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

		Page
	PART I	
Items 1 & 2.	Business and Properties	3
Item 1A.	Risk Factors	14
Item 1B.	Unresolved Staff Comments	19
Item 3.	Legal Proceedings	19
Item 4.	Submission of Matters to a Vote of Security Holders	19
Item 4A.	Executive Officers of the Registrant	19
	PART II	
Item 5.	Market for the Registrant s Common Stock and Related Stockholder Matters	20
Item 6.	Selected Financial Data	21
Item 7.	Management s Discussion and Analysis of Financial Condition and Results of Operations	22
Item 7A.	Quantitative and Qualitative Disclosures about Market Risk	34
Item 8.	Financial Statements and Supplementary Data	36
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	66
Item 9A.	Controls and Procedures	66
Item 9B.	Other Information	66
	PART III	
Item 10.	Directors and Executive Officers of the Registrant	67
Item 11.	Executive Compensation	67
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	67
Item 13.	Certain Relationships and Related Transactions	67
Item 14.	Principal Accountant Fees and Services	67
	PART IV	
Item 15.	Exhibits and Financial Statement Schedules	67

Certificate of Elimination of Series D Exchangeable Convertible Preferred Stock
Subsidiaries of Energy Partners, Ltd.
Consent of KPMG LLP
Consent of Netherland, Sewell & Associates, Inc.
Consent of Ryder Scott Company, L.P.
Rule 13a-14a/15d-14a Certification of Chairman, President and CEO
Rule 13a-14a/15d-14a Certification of Executive VP and CFO
Section 1350 Certifications
Report of Independent Petroleum Engineers dated February 14, 2006
Report of Independent Petroleum Engineers dated February 7, 2006

Table of Contents

FORWARD LOOKING STATEMENTS

All statements other than statements of historical fact contained in this Report on Form 10-K (Report) and other periodic reports filed by us under the Securities Exchange Act of 1934 and other written or oral statements made by us or on our behalf, are forward-looking statements. When used herein, the words anticipates , expects , believes , goals intends , plans , or projects and similar expressions are intended to identify forward-looking statements. It is important to note that forward-looking statements are based on a number of assumptions about future events and are subject to various risks, uncertainties and other factors that may cause our actual results to differ materially from the views, beliefs and estimates expressed or implied in such forward-looking statements. We refer you specifically to the section Risk Factors in Item 1A of this Report. Although we believe that the assumptions on which any forward-looking statements in this Report and other periodic reports filed by us are reasonable, no assurance can be given that such assumptions will prove correct. All forward-looking statements in this Report are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this Report.

PART I

Items 1 & 2. *Business and Properties*

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 of the Gulf of Mexico Shelf and the Gulf Coast onshore regions and, as a result of an acquisition of undeveloped acreage in early 2006, the deepwater Gulf of Mexico. We concentrate on this core focus area because it provides 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. In addition, we intend to evaluate reserve and exploratory acquisition opportunities outside of our core focus area. As of December 31, 2005, we had estimated proved reserves of approximately 166.9 Bcf of natural gas and 31.5 Mmbbls of oil, or an aggregate of approximately 59.3 Mmboe, with a present value of estimated pre-tax future net cash flows of $1.8 billion, and a standardized measure of discounted future net cash flows of $1.3 billion.

We have a team of geoscientists and management professionals with considerable region-specific geological, geophysical, technical and operational experience. We have grown 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 Gulf of Mexico Shelf and the Gulf Coast onshore areas. As we have grown, we have strengthened our management team, expanded our property base, reduced our geographic concentration, and moved to a more balanced oil and natural gas reserves and production profile. We have also expanded our technical knowledge base through the addition of high quality personnel and geophysical and geological data.

Our common stock is traded on the New York Stock Exchange under the symbol EPL. We maintain a website at www.eplweb.com which contains information about us, including links to our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all related amendments. In addition, our website contains our Corporate Governance Guidelines and the charters for our Audit, Compensation and Nominating Committees. Copies of such information are also available by writing to the Secretary of the Company at 201 St. Charles Avenue, Suite 3400, New Orleans, Louisiana 70170. Our web site and the information contained in it and connected to it shall not be deemed incorporated by reference into this Report on Form 10-K.

Acquisition of South Louisiana Reserves and Prospects

On January 20, 2005, we closed an acquisition of properties and reserves onshore in south Louisiana for $149.6 million in cash, after adjustments for the exercise of preferential rights by third parties and closing adjustments. The properties acquired included nine fields, four of which were producing at the time of the closing through 14 wells, with estimated acquisition date proved reserves of 51.2 Bcfe. Also included were interests in

Table of Contents

22 exploratory prospects. The transaction expanded the exploration opportunities in our expanded focus area. Concurrent with the closing, our bank credit facility borrowing base was increased to $150 million, of which $60 million was drawn to fund the acquisition. In connection with the acquisition, we also entered into a two-year agreement with the seller of the properties that defines an area of mutual interest (AMI) encompassing over one million acres. We intend to continue to explore and develop oil and natural gas reserves in the AMI over the two year term jointly with the seller. The proved reserves acquired from the seller, prospects and the AMI are in the southern portions of Terrebone, Lafourche and Jefferson Parishes in Louisiana.

Exploration and Development Expenditures

Our exploration and development expenditures for 2005 totaled $478.7 million inclusive of a $0.9 million contingent consideration payment to former stockholders of a company acquired in 2002 and $170.5 million related to acquisitions in 2005. For 2006, we have budgeted exploration and development expenditures of $360 million. The drilling portfolio, both onshore and offshore, includes a mixture of lower risk development and exploitation wells, moderate risk exploration opportunities and higher risk, higher potential exploration projects. Our 2006 budget does not include any acquisitions of proved reserves that may occur during the year.

Our Properties

At December 31, 2005, we had interests in 38 producing fields and 5 fields under development all of which are located in the Gulf of Mexico Shelf and the Gulf Coast onshore regions (the Gulf of Mexico Region). These fields fall into four focus areas which we identify as our Eastern, Central and Western offshore and Gulf Coast onshore areas. The Eastern offshore area is comprised of two producing fields, including the East Bay field. The Central offshore area is comprised of six producing fields, four of which are contiguous and cover most of the Bay Marchand salt dome. The Western offshore area, which extends from areas offshore central and western Louisiana to areas offshore Texas, is comprised of 21 producing fields. Our Gulf Coast onshore area is located in South Louisiana, with nine producing fields. Over the last several years, we have continued to add 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 is the key asset in our Eastern offshore area and is located 89 miles southeast of New Orleans near the mouth of the Mississippi River. East Bay contains producing wells located onshore along the coastline and in water depths ranging up to approximately 171 feet. East Bay is comprised primarily of the South Pass 24, 26 and 27 fields. Through a number of state and federal lease sales, we have acquired acreage that is contiguous to East Bay in several additional South Pass blocks as well as across the river in West Delta blocks. We own an average 96% interest in our acreage position in this area with our working interest ranging from 18% to 100% and our net revenue interest varying up to a maximum of 86%. Inclusive of all lease acquisitions, our leasehold area covered 47,307 gross acres (45,403 net acres) at the end of 2005. Our Eastern offshore area operations accounted for approximately 21% of our net daily production during 2005.

Central Offshore Area

The core assets of our Central offshore area, the fields located in Greater Bay Marchand, 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 and 41 and Bay Marchand fields as well as currently undeveloped reserves in the South Timbalier 46 field. Our Central offshore area operations accounted for approximately 40% of our net daily production during 2005.

In 2003, we drilled our initial discovery well in South Timbalier 41 field on acreage acquired earlier that year in a federal lease sale. Five follow up exploratory wells have been drilled in the field and all have been successful. Four of these wells have been brought on production and an additional development well was drilled in early 2006. This field, in which additional reserve potential is yet to be tested, represents the most significant discovery in our history. We acquired acreage in eight additional leases in the vicinity of this field in the March 2005 federal lease sale.

In addition, we owned a 50% interest in the South Timbalier 26 field at the beginning of 2005. On March 8, 2005, we closed the acquisition of the remaining 50% interest in South Timbalier 26 above 13,000 feet subsea for approximately $19.6 million after closing adjustments. As a result of the acquisition, we now own a 100% interest in the producing horizons in this field. The acquisition expands our interest in our core Greater Bay Marchand area and gives us additional flexibility in undertaking the future development of the South Timbalier 26 field. We have interests in 12 producing wells in this field.

Western Offshore Area

The properties in the Western offshore area are located in water depths ranging from 20 to 476 feet with working interests ranging from 17% to 100%. We owned interests in 25 fields in this area at December 31, 2005, 21 of which were producing fields with another four under development. Our Western offshore area operations accounted for approximately 25% of our net daily production during 2005.

Gulf Coast Onshore Area

The properties in the Gulf Coast onshore area are located in south Louisiana with working interests ranging from 8% to 100%. We owned interests in nine producing fields in this area at December 31, 2005. Our Gulf Coast onshore area operations accounted for approximately 14% of our net daily production during 2005.

Oil and Natural Gas Reserves

The following table presents our estimated net proved oil and natural gas reserves and the present value of our reserves at December 31, 2005, 2004 and 2003. The December 31, 2005, 2004 and 2003 estimates of proved reserves are based on reserve reports prepared by Netherland, Sewell & Associates, Inc. and Ryder Scott Company, L.P., independent petroleum engineers. Neither the present values, discounted at 10% per annum, of estimated future net cash flows before income taxes, 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 we own.

	As of December 31,		
	2005	**2004**	**2003**
Total estimated net proved reserves(1):			
Oil (Mbbls)	31,478	28,770	27,414
Natural gas (Mmcf)	166,949	149,835	134,404
Total (Mboe)	59,303	53,743	49,815
Net proved developed reserves(2):			
Oil (Mbbls)	25,656	24,737	22,306
Natural gas (Mmcf)	103,627	102,760	71,531
Total (Mboe)	42,917	41,864	34,228
Estimated future net revenues before income taxes (in thousands)(3)	$ 2,531,166	$ 1,271,083	$ 967,449
Present value of estimated future net revenues before income taxes (in thousands)(3) (4)	$ 1,806,185	$ 924,135	$ 701,237
Standardized measure of discounted future net cash flows (in thousands)(5)	$ 1,261,246	$ 667,668	$ 529,415

(1) Approximately 82% of our total proved reserves were proved undeveloped and proved developed non-producing at December 31, 2005.

(2) Net proved developed non-producing reserves as of December 31, 2005 were 19,884 Mbbls and 72,420 Mmcf.

Table of Contents

(3) The December 31, 2005 amount was calculated using a period-end oil price of $57.81 per barrel and a period-end natural gas price of $10.31 per Mcf, while the December 31, 2004 amount was calculated using a period-end oil price of $41.84 per barrel and a period-end natural gas price of $6.23 per Mcf and the December 31, 2003 amount was calculated using a period-end oil price of $30.88 per barrel and a period-end natural gas price of $6.15 per Mcf.

(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 tax discounted at 10%.

Costs Incurred in Oil and Natural Gas Activities

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

	Years Ended December 31, 2005	2004	2003
	(In thousands)		
Business combinations:			
Proved properties	$ 142,025	$ 2,166	$ 850
Unproved properties	29,333		
Total business combinations	171,358	2,166	850
Lease acquisitions	27,622	6,551	6,030
Exploration	171,859	113,278	60,170
Development(1)	114,814	75,732	49,013
Costs incurred	$ 485,653	$ 197,727	$ 116,063

(1) Includes asset retirement obligations incurred of $6.9 million, $3.5 million and $3.3 million for the years ended December 31, 2005, 2004 and 2003, respectively.

Productive Wells

The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2005:

	Total Productive Wells Gross	Net

Oil	266	201
Natural gas	118	58
Total	384	259

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. Seventeen gross oil wells and eight gross natural gas wells have dual completions.

Acreage

The following table sets forth information as of December 31, 2005 relating to acreage held by us. Developed acreage is assigned to producing wells.

	Gross Acreage	Net Acreage
Developed:		
Eastern area	32,229	30,988
Central area	38,840	24,206
Western area	131,214	80,427
Gulf Coast onshore area	6,496	2,786
Total	208,779	138,407
Undeveloped:		
Eastern area	15,078	14,415
Central area	39,240	38,139
Western area	170,159	123,110
Gulf Coast onshore area	7,070	2,527
Total	231,547	178,191

Leases covering 12% of our undeveloped net acreage will expire in 2006, approximately 6% in 2007, 5% in 2008, 24% in 2009, 46% in 2010 and 7% thereafter.

Well Activity

The following table shows our well activity for the years ended December 31, 2005, 2004 and 2003. In the table, gross refers to the total wells in which we have a working interest and net refers to gross wells multiplied by our working interest in these wells.

	Years Ended December 31,					
	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	8.0	4.7	5.0	3.2	1.0	0.3
Non-productive	3.0	1.1	2.0	2.0	1.0	1.0
Total	11.0	5.8	7.0	5.2	2.0	1.3
Exploration Wells:						
Productive	30.0	15.3	19.0	12.3	15.0	8.4
Non-productive	17.0	9.3	5.0	2.2	4.0	2.2

Total	47.0	24.6	24.0	14.5	19.0	10.6

Well activity refers to the number of wells completed at any time during the fiscal years, regardless of when drilling was initiated. For the purpose of this table, completed refers to the installation of permanent equipment for the production of oil or natural gas.

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

Regulatory Matters

Regulation of Transportation and Sale of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, as amended (NGA), the Natural Gas Policy Act of 1978, as amended (NGPA), and regulations promulgated thereunder by the Federal Energy Regulatory Commission (FERC) and its predecessors. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at unregulated market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, as amended (the Decontrol Act). The Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, FERC issued Order No. 636 and a series of related orders (collectively, Order No. 636) to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly altered. The interstate pipelines traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although FERC s orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, FERC issued Order No. 637 and subsequent orders (collectively, Order No. 637), which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised FERC pricing policy by waiving price ceilings for short-term released capacity for a two-year experimental period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. Most major aspects of Order No. 637 have been upheld on judicial review, and most pipelines tariff filings to implement the requirements of Order No. 637 have been accepted by the FERC and placed into effect.

The Outer Continental Shelf Lands Act (OCSLA), which FERC implements as to transportation and pipeline issues, requires that all pipelines operating on or across the outer continental shelf (OCS) provide open access, non-discriminatory transportation service. One of FERC s principal goals in carrying out OCSLA s mandate is to increase transparency in the market to provide producers and shippers on the OCS with greater assurance of open access service on pipelines located on the OCS and non-discriminatory rates and conditions of service on such pipelines. The U.S. Minerals Management Service (MMS) also has jurisdiction under OCSLA to ensure that all shippers seeking service on OCS pipelines transporting oil or gas pursuant to MMS-granted easements or rights-of-way receive open and non-discriminatory access to such transportation. In furtherance of this mandate, MMS currently is contemplating rulemaking to amend its regulations to better ensure such access for OCS shippers.

It should be noted that FERC currently is considering whether to reformulate its test for defining non-jurisdictional gathering in the shallow waters of the OCS and, if so, what form that new test should take. The stated purpose of this initiative is to devise an objective test that furthers the goals of the NGA by protecting producers from the unregulated market power of third-party transporters of gas, while providing incentives for investment in production, gathering and transportation infrastructure offshore. While we cannot predict whether FERC s

Table of Contents

gathering test ultimately will be revised and, if so, what form such revised test will take, any test that refunctionalizes as FERC-jurisdictional transmission facilities currently classified as gathering would impose an increased regulatory burden on the owner of those facilities by subjecting the facilities to NGA certificate and abandonment requirements and rate regulation.

We cannot accurately predict whether FERC s (or MMS s) actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before FERC and the courts. For example, the Federal Energy Policy Act, signed into law in August 2005, contains various provisions designed to increase the level of competition and transparency in FERC-regulated natural gas markets (e.g. one such provision makes market-based rate authority generally available to new interstate natural gas storage facilities), those provisions are now in various stages of implementation by FERC. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is materially different from the effect of such regulation on our competitors.

Regulation of Transportation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. The transportation of oil in common carrier pipelines is also subject to rate regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. A review of these regulations by the FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. On remand, the FERC in February 2003 increased the index slightly, effective July 2001. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is materially different from the effect of such regulation on our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Our subsidiary, EPL Pipeline, L.L.C., owns an approximately 12-mile oil pipeline, which transports oil produced from South Timbalier 26 and a portion of South Timbalier 41 on the Gulf of Mexico OCS to Bayou Fourchon, Louisiana. Production transported on this pipeline includes oil produced by us and our working interest partner in South

Timbalier 26. EPL Pipeline, L.L.C. has on file with the Louisiana Public Service Commission and FERC tariffs for this transportation service and offers non-discriminatory transportation for any willing shipper.

Table of Contents

Regulation of Production

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. Federal, state and local statutes and regulations require permits for drilling operations, drilling and plugging and abandonment surety bonds and reports concerning operations. The states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. Many states also restrict production to the market demand for oil and natural gas, and states have indicated interest in revising applicable regulations. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Some of our offshore operations are conducted on federal leases that are administered by MMS and are required to comply with the regulations and orders promulgated by MMS under OCSLA. Among other things, we are required to obtain prior MMS approval for any exploration plans we pursue and our development and production plans for these leases. MMS regulations also establish construction requirements for production facilities located on our federal offshore leases and govern the plugging and abandonment of wells and the removal of production facilities from these leases. Under limited circumstances, MMS could require us to suspend or terminate our operations on a federal lease.

MMS also establishes the basis for royalty payments due under federal oil and natural gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and natural gas leases. The basis for royalty payments established by MMS and the state regulatory authorities is generally applicable to all federal and state oil and natural gas lessees. Accordingly, we believe that the impact of royalty regulation on our operations should generally be the same as the impact on our competitors.

The failure to comply with these rules and regulations can result in substantial penalties. 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.

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 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 legislation. 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 activities on certain lands lying within wilderness, wetlands and other protected areas; and

impose substantial liabilities for pollution resulting from our 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, as well as those in the oil and natural gas industry in general. While we believe that we are in substantial compliance with current

Table of Contents

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 with the industry generally, compliance with existing 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 and damages to natural resources, without regard to fault or the legality of the original act, on some classes of persons that contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of a disposal site 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. 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. 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, hydrocarbons or other wastes 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 hydrocarbons or other wastes were not under our control. These properties and wastes disposed on these properties may be subject to 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; or

- to perform remedial operations to prevent future contamination.

At this time, we do not believe that we are 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. Liability under OPA is strict, and under certain circumstances joint and several, and potentially unlimited. 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. The 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 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.

U.S. Environmental Protection Agency. U.S. Environmental Protection Agency regulations address the disposal of oil and natural gas operational wastes under three federal acts more fully discussed in the paragraphs that follow. The Resource Conservation and Recovery Act of 1976, as amended (RCRA), provides a framework for the safe disposal of discarded materials and the management of solid and hazardous wastes. The direct disposal of operational wastes into offshore waters is also limited under the authority of the Clean Water Act. When injected underground, oil and natural gas wastes are regulated by the Underground Injection Control program under Safe Drinking Water Act. If wastes are classified as hazardous, they must be properly transported, using a uniform hazardous waste manifest, documented, and disposed at an approved hazardous waste facility. We have coverage under the Clean Water Act permitting requirements for discharges associated with exploration and development activities. We take the necessary steps to ensure all offshore discharges associated with a proposed operation, including produced waters, will be conducted in accordance with such requirements.

Resource Conservation Recovery Act. RCRA, is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating 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 includes a statutory exemption that allows most oil and natural gas exploration and production waste to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA s requirements because our operations generate minimal quantities of hazardous wastes. 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 produced waters 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 and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. 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. Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and natural gas production. The Safe Drinking Water Act of 1974, as amended establishes a regulatory framework for underground injection, with the main goal being the protection of usable aquifers. 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. Hazardous-waste injection well operations are strictly controlled, and certain wastes, absent an exemption, cannot be injected into underground injection control wells. 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 abide by 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.

Marine Mammal and Endangered Species. Federal Lease Stipulations Executive Order 13158 (Marine Protected Areas) address the protection of marine areas and the reduction of potential taking of protected marine species (sea turtles, marine mammals, Gulf Sturgen and other listed marine species). MMS permit approvals will be conditioned on collection and removal of debris resulting from activities related to exploration, development and production of offshore leases. MMS has issued Notices to Lessees and Operators (NTL) 2003-G06 advising of requirements for posting of signs in prominent places on all vessels and structures and of an observing training program.

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operations frequently require licenses, permits and/or other governmental approvals. Several federal statutes, including OCSLA, the National Environmental Policy Act (NEPA), and the Coastal Zone Management Act (CZMA) require federal agencies to evaluate environmental issues in connection with granting such approvals and/or taking other major agency actions. OCSLA, for instance, requires the U.S. Department of Interior (DOI) to evaluate whether certain proposed activities would cause serious harm or damage to the marine, coastal or human environment. Similarly, NEPA requires DOI and other federal agencies to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency would have to prepare an environmental assessment and, potentially, an environmental impact statement. CZMA, on the other hand, aids states in developing a coastal management program to protect the coastal environment from growing demands associated with various uses, including offshore oil and natural gas development. In obtaining various approvals from the DOI, we must certify that we will conduct our activities in a manner consistent with an applicable program.

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 might also require us to institute certain administrative and/or engineering controls required by the Occupational Safety and Health Act and MMS to ensure worker safety during paint removal.

Air Pollution Control. The Clean Air Act and state air pollution laws adopted to fulfill its mandates provide a framework for national, state and local efforts to protect air quality. Our operations utilize equipment that emits air pollutants subject to federal 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. Air emissions associated with offshore activities are projected using a matrix and formula supplied by MMS, which has primacy from the Environmental Protection Agency for regulating such emissions.

Naturally Occurring Radioactive Materials (NORM). NORM are materials not covered by the Atomic Energy Act, 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 established by the State of Louisiana or the State of Texas, as applicable.

Abandonment Costs. One of the responsibilities of owning and operating oil and natural gas properties is paying for the cost of abandonment. Companies are required to reflect abandonment costs as a liability on their balance sheets in the period in which it is incurred. We may incur significant abandonment costs in the future which could adversely affect our financial results.

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. A majority of oil production from the East Bay field is sold under a contract with Shell Trading (US) Company (Shell). The contract has a 60 day cancellation provision and can be terminated

Table of Contents

by either party. In the event that the contract is cancelled by us, Shell has the right through 2007 to match any other offers we receive for the purchase of this oil production. Our oil, condensate and natural gas production is sold to a variety of purchasers, which has historically been at market-sensitive prices. Our purchasers of oil and condensate include Chevron Products Company (Chevron) and Shell. Currently, the most significant purchaser of our natural gas production is Louis Dreyfus Energy Services, L.P. (Dreyfus). 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 2005, Dreyfus accounted for approximately 18%, Shell 16%, Bridgeline Holdings, L.P. 15% and Chevron 10%.

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.

Employees

As of December 31, 2005, we had 170 full-time employees, including 45 geoscientists, engineers and technicians and 63 field personnel. Our employees are not represented by any labor union. We consider relations with our employees to be satisfactory and we have never experienced a work stoppage or strike.

Item 1A. ***Risk Factors***

Risks Relating to the Oil and Natural Gas Industry

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

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

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

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

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;
- personal injuries and death; and
- natural disasters, especially hurricanes and tropical storms in the Gulf of Mexico.

Offshore operations are also subject to a variety of operating risks peculiar 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 to our company. 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 hurricane season in the Gulf of Mexico, in particular those resulting from Hurricanes Katrina and Rita. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect our cash flow and net income and could reduce or eliminate the funds available for exploration, exploitation and acquisitions or result in loss of equipment and properties.

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure requirements and financial commitments.

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, 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, or OPEC;
- the price and quantity of foreign imports of oil;

the price and availability of liquefied natural gas imports;

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

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

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

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

Table of Contents

- weather conditions, including energy infrastructure disruptions resulting from those conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis, but also may reduce the amount of oil and natural gas that we can produce economically. A substantial or extended decline in oil and natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity, ability to finance planned capital expenditures or ability to pursue acquisitions. Further, oil prices and natural gas prices do not necessarily move together.

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 present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires 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 shown in this Report.

In order to assist in the preparation of our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of these data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates.

It cannot be assumed that the present value of future net revenues from our proved reserves referred to in this Report is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present-value estimate.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could harm our business. We may be required to shut in wells for lack of a market or because of inadequacy or unavailability of oil or natural gas pipeline or gathering system capacity. If that were to occur, we would be unable to realize revenue from those wells until production arrangements were made to deliver to market.

Risks Relating to Energy Partners, Ltd.

A significant part of the value of our production and reserves is concentrated in two areas. Because of this concentration, any production problems or inaccuracies in reserve estimates related to these areas could impact our business adversely.

During 2005, 39% of our net daily production came from our Greater Bay Marchand area and approximately 40% of our proved reserves were located in the fields that comprise this area. In addition, 20% of our net daily production came from our East Bay field and approximately 34% of our proved reserves were located on this

16

property. If mechanical problems, storms or other events were to curtail a substantial portion of this production, our cash flow could be affected adversely. If the actual reserves associated with these properties are less than our estimated reserves, our business, financial condition or results of operations could be adversely affected.

Relatively short production life for Gulf of Mexico and Gulf Coast onshore regions properties 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 production rates generally result in recovery of a relatively higher percentage of reserves from properties during the initial few years of production. All of our operations are presently in the Gulf of Mexico and Gulf Coast onshore regions. Production from reservoirs in the Gulf of Mexico region generally declines more rapidly than from reservoirs in many other producing regions of the world. As of December 31, 2005, our independent petroleum engineers estimate, on average, 65% of our total proved reserves will be produced within 5 years. As a result, our reserve replacement needs from new investments are relatively greater than those of producers who recover lower percentages of their reserves over a similar time period, such as producers who have a portion of their reserves outside the Gulf of Mexico in areas where the rate of reserve production is lower. We may not be able to develop, exploit, find or acquire additional reserves to sustain our current production levels or to grow. 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, and, therefore, our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

Rapid growth may place significant demands on our resources.

We have experienced rapid growth in our operations and expect that expansion of our operations will continue. Our rapid growth has placed, and our anticipated future growth will continue to place, a significant demand on our managerial, operational and financial resources due to:

- the need to manage relationships with various strategic partners and other third parties;
- difficulties in hiring and retaining skilled personnel necessary to support our business;
- complexities in integrating acquired businesses and personnel;
- the need to train and manage our employee base; and
- pressures for the continued development of our financial and information management systems.

If we have not made adequate allowances for the costs and risks associated with these demands or if our systems, procedures or controls are not adequate to support our operations, our business could be harmed.

Properties that we buy may not produce as projected, and we may be unable to fully identify liabilities associated with the properties or obtain protection from sellers against them.

Our strategy includes acquisitions. The successful acquisition of producing properties requires 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; and

potential environmental and other liabilities.

Our assessments will not reveal all existing or potential problems, nor will they permit us to become familiar enough with the properties to evaluate fully their deficiencies and capabilities. In the course of our due diligence, we may not inspect every well, platform or pipeline. We cannot necessarily observe structural and environmental problems, such as pipeline corrosion or groundwater contamination, when an inspection is conducted. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Substantial acquisitions, development programs or other transactions could require significant external capital and could change our risk and property profile.

In order to finance acquisitions of additional producing properties or finance the development of any discoveries made through any expanded exploratory program that might be undertaken, we may need to alter or increase our capitalization substantially through the issuance of additional debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for any such transactions or to obtain additional external funding on terms acceptable to us.

The unavailability or high cost 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 within our budget.

All of our operations are in the Gulf of Mexico and Gulf Coast onshore regions. Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our exploration and development plans, which could have a material adverse effect on our business, financial condition or results of operations. 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. We cannot offer assurance that costs will not increase again or that necessary equipment and services will be available to us at economical prices.

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 act by written consent and 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.

The loss of key personnel could adversely affect us.

To a large extent, we depend on the services of our chairman and chief executive officer, Richard A. Bachmann, our president and chief operating officer, Phillip A. Gobe, and other senior management personnel. The loss of the services of Messrs. Bachmann or Gobe or other senior management personnel could have an adverse effect on our operations. We do not maintain any insurance against the loss of any of these individuals.

Table of Contents

The exploration and production business is highly competitive, and our success will depend largely on our ability to attract and retain experienced geoscientists and other professional staff.

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. We cannot make assurances 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.

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

None.

Item 3. ***Legal Proceedings***

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

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

None

Item 4A. ***Executive Officers of the Registrant***

The following table sets forth certain information regarding our executive officers:

Name	Age	Position
Richard A. Bachmann	61	Chairman and Chief Executive Officer
Phillip A. Gobe	53	Director, President and Chief Operating Officer
David R. Looney	49	Executive Vice President and Chief Financial Officer
John H. Peper	53	Executive Vice President, General Counsel and Corporate Secretary
T. Rodney Dykes	49	Senior Vice President Production

Richard A. Bachmann has been chief executive officer and chairman of the board of directors since our incorporation in January 1998 and also served as our president until May 2005. Mr. Bachmann began organizing our company in February 1997. From 1995 to January 1997, he served as director, president and chief operating officer of LL&E, an independent oil and natural gas exploration company. From 1982 to 1995, Mr. Bachmann held various positions with LL&E, including director, executive vice president, chief financial officer and senior vice president of finance and administration. From 1978 to 1981, Mr. Bachmann was treasurer of Itel Corporation. Prior to 1978, Mr. Bachmann served with Exxon International, Esso Central America, Esso InterAmerica and Standard Oil of New Jersey. He also serves as a director of Trico Marine Services, Inc.

Phillip A. Gobe joined us in December 2004 as chief operating officer and was elected president in May 2005 and appointed a director in November 2005. Mr. Gobe has over 29 years of energy industry experience and was with

Table of Contents

Nuevo Energy Company as chief operating officer from February 2001 until its acquisition by Plains Exploration & Production Company in May 2004. Mr. Gobe s primary responsibilities were managing Nuevo s domestic and international exploitation and exploration operations. Prior to his position with Nuevo, Mr. Gobe had been the Senior Vice President of Production for Vastar Resources, Inc. since 1997. From 1976 to 1997, Mr. Gobe worked for Atlantic Richfield Company and its subsidiaries in positions of increasing responsibility, primarily in the Gulf of Mexico and Alaska.

David R. Looney joined us in February 2005 and was elected executive vice president and chief financial officer in March 2005. Prior to joining us Mr. Looney had been with EOG Resources Inc. (EOG), where he served as Vice President, Finance, a position he had held since 1999. In that role his responsibilities included all finance and treasury functions including managing external relationships with investment banks, commercial banks and the rating agencies. Mr. Looney joined EOG in 1998 as Assistant Treasurer after holding a variety of financial roles at firms including Toronto-Dominion Bank and Chase Manhattan Bank.

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

T. Rodney Dykes joined us in April 2001 as general manager of operations and was elected vice president of operations in July 2001. He served as our vice president of exploitation for the period from March 2002 through July 2003 and was elected senior vice president production in July 2003. Mr. Dykes has over 25 years experience in the energy industry. Immediately prior to joining us, Mr. Dykes worked as an independent consultant. From 1994 to 1999, Mr. Dykes held various positions with CMS Oil and Gas Company, including divisional operations manager, vice president of operations and vice president of business development. From 1980 to 1994, he held various technical, drilling and production management positions with Maxus Energy. Prior to 1980, Mr. Dykes was a petroleum engineer with Kerr McGee.

PART II

Item 5. *Market for Registrant s Common Stock and Related Stockholder Matters*

Our common stock is listed on the New York Stock Exchange 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 New York Stock Exchange.

	High	Low
2004		
First Quarter	$ 14.81	$ 12.60
Second Quarter	15.45	12.60
Third Quarter	16.59	14.00
Fourth Quarter	20.91	16.07
2005		
First Quarter	27.97	18.38
Second Quarter	28.63	19.06
Third Quarter	32.98	22.20

Fourth Quarter	32.30	21.25
2006		
First Quarter (through February 22, 2006)	28.68	22.00

On February 22, 2006 the last reported sale price of our common stock on the New York Stock Exchange was $23.89 per share.

Table of Contents

As of February 22, 2006 there were approximately 125 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 on our common stock in the foreseeable future. We intend to retain earnings for the future operation and development of our business. Any future cash dividends to holders of common stock would depend on future earnings, capital requirements, our financial condition and other factors determined by our board of directors.

Item 6. *Selected Financial Data*

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

	Years Ended December 31,				
	2005	2004	2003	2002	2001
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenue	$ 402,947	$ 295,210	$ 230,187	$ 133,788	$ 146,240
Income (loss) from operations(1)	132,027	86,068	58,560	(6,600)	20,663
Net income (loss)(2)	73,095	46,416	33,250	(8,799)	11,974
Net income (loss) available to common stockholders(3)	72,151	43,017	29,705	(12,129)	11,974
Basic net income (loss) per common share	$ 1.94	$ 1.31	$ 0.96	$ (0.44)	$ 0.45
Diluted net income (loss) per common share	$ 1.79	$ 1.20	$ 0.93	$ (0.44)	$ 0.44
Cash flows provided by (used in):					
Operating activities	$ 269,969	$ 165,074	$ 136,702	$ 25,417	$ 91,847
Investing activities	(449,159)	(176,713)	(110,057)	(54,380)	(121,067)
Financing activities	92,442	784	77,631	29,079	25,871

	As of December 31,				
	2005	2004	2003	2002	2001
	(In thousands)				
Balance Sheet Data:					
Total assets	$ 931,285	$ 647,678	$ 544,181	$ 384,220	$ 242,777
Long-term debt, excluding current maturities	235,000	150,109	150,317	103,687	25,408
Stockholders equity	394,593	315,049	261,485	191,922	164,867
Cash dividends per common share					

(1) The 2005 income from operations includes accrued business interruption insurance recoveries of $20.6 million from deferred production at four of our fields resulting form Hurricanes Katrina and Rita.

(2) The 2003 net income includes a cumulative effect of change in accounting principle resulting from the adoption of Statement 143, which increased net income $2.3 million, net of deferred income taxes of $1.3 million.

(3) Net income (loss) available to common stockholders is computed by subtracting preferred stock dividends and accretion of discount of $0.9 million, $3.4 million, $3.5 million and $3.3 million from net income (loss) for the years ended December 31, 2005, 2004, 2003 and 2002, respectively.

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

Overview

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 of the Gulf of Mexico Shelf and contiguous Gulf Coast onshore region.

While the impacts of Hurricanes Katrina, Rita, Cindy, Dennis and Emily (the Tropical Weather) were significant to 2005, we still made progress toward implementing our long-term growth strategy to increase our oil and natural gas reserves and production while keeping our finding and development costs and operating costs competitive with our industry peers. Our strong cash flow provided us the flexibility to make necessary and appropriate investments to continue this growth strategy. We will implement this strategy through drilling exploratory and development wells from our inventory of available prospects that we have evaluated for geologic and mechanical risk and future reserve or resource potential and by making acquisitions, including acquisitions in our core focus area which includes the Gulf of Mexico Shelf and onshore Gulf Coast regions and, as a result of an acquisition of undeveloped acreage in early 2006, the deepwater Gulf of Mexico. We also evaluate acquisition opportunities outside of our core focus area as a complement to the drilling and development activities we have budgeted for that area. Our drilling program will contain some higher risk, higher reserve potential opportunities as well as some lower risk, lower reserve potential opportunities, in order to achieve a balanced program of reserve and production growth.

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. 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.

In connection with the acquisition of a company in January 2002, its former preferred stockholders have the right to receive contingent consideration based upon a percentage of the amount by which the before tax net present value of proved reserves related, in general, to exploratory prospect acreage held by the acquired company as of the closing date exceeds a net present value discounted at 30%. The contingent consideration may be paid in our common stock or cash at our option (with a minimum of 20% paid in cash for each payment) and in no event will exceed a value of $50 million. Due to the uncertainty inherent in estimating the value of the contingent consideration, total final consideration will not be determined until March 1, 2007. The contingent consideration paid will be capitalized as additional purchase price.

On April 16, 2003, we completed the public offering of approximately 4.2 million shares of our common stock priced at $9.50 per share. The equity offering also included shares offered by our then principal stockholder, Evercore Capital Partners, L.P. and certain of its affiliates (Evercore), and by Energy Income Fund, L.P. (EIF). After payment of underwriting discounts and commissions, the offering generated net proceeds to us of approximately $38.0 million. After expenses of approximately $0.5 million, the proceeds were used to repay a portion of outstanding borrowings under our bank credit facility.

On August 5, 2003, we issued $150 million of 8.75% Senior Notes due 2010 (the Senior Notes) in a Rule 144A private offering (the Debt Offering) which allows unregistered transactions with qualified institutional and non-U.S. purchasers. After discounts and commissions and all offering expenses, we received $145.3 million, which was used to redeem all of our outstanding 11% Senior Subordinated Notes due 2009 (the 11% Notes) and to repay substantially all of the borrowings outstanding under our bank credit facility. The remainder of the net proceeds was set aside for general corporate purposes, including acquisitions. In October 2003, we consummated an exchange offer pursuant to which we exchanged registered Senior Notes having substantially identical terms as the Senior Notes for the privately placed Senior Notes.

On July 16, 2004, we filed a universal shelf registration statement (the Registration Statement) which allows us to issue an aggregate of $300 million in common stock, preferred stock, senior debt and subordinated debt in one or more separate offerings with the size, price and terms to be determined at the time of the sale. On November 10, 2004 we sold approximately 3.5 million shares of our common stock to the public pursuant to the Registration

Table of Contents

Statement. Concurrent with this offering, we entered into a stock purchase agreement with EIF pursuant to which we purchased an equal number of shares of common stock owned by EIF at a price per share equal to the proceeds per share received in the offering, before expenses. We did not retain any of the proceeds from the offering and the shares are now held as treasury shares, at cost. We restored the Registration Statement to $300 million in May 2005. We have no immediate plans to enter into any additional transactions under the Registration Statement, but plan to use the proceeds of any future offering under the Registration Statement for general corporate purposes, which may include debt repayment, acquisitions, expansion and working capital.

On August 3, 2004 we amended and extended to August 3, 2008 our bank credit facility. The borrowing base was increased to $150 million at the time of our purchase of south Louisiana properties and reserves in January 2005. At December 31, 2005 we had $85 million outstanding under our bank credit facility. The borrowing base remains subject to redetermination based on the proved reserves of the oil and natural gas properties that serve as collateral for the bank credit facility. Our borrowing base was reaffirmed effective November 1, 2005.

On January 20, 2005, we closed an acquisition of properties and reserves in south Louisiana for $149.6 million in cash, after adjustments for the exercise of preferential rights by third parties and closing adjustments. The acquisition was composed of nine fields, four of which were producing at the time of the closing through 14 wells, with estimated acquisition date proved reserves of 51.2 billion cubic feet equivalent. Also included were interests in 22 exploratory prospects. The transaction expanded the exploration opportunities in our expanded focus area. Upon the signing of the purchase agreement, we paid a $5.0 million deposit in 2004 toward the purchase price which was recorded as other assets in the year-end 2004 consolidated balance sheet, and concurrent with the closing, the borrowing base under our bank credit facility was increased to $150 million, of which $60 million was drawn to fund the acquisition. In connection with the acquisition, we also entered into a two-year agreement with the seller of the properties that defined an area of mutual interest (AMI) encompassing over one million acres. We intend to continue to explore and develop oil and natural gas reserves in the AMI over the two year term jointly with the seller. The proved reserves, prospects and the AMI are in the southern portions of Terrebone, Lafourche and Jefferson Parishes in Louisiana.

On March 8, 2005, we closed the acquisition of the remaining 50% gross working interest in South Timbalier 26 above approximately 13,000 feet subsea that we did not already own for approximately $19.6 million after closing adjustments. As a result of the acquisition, we now own a 100% gross working interest in the producing horizons in this field. The acquisition expands our interest in our core Greater Bay Marchand area and has given us additional flexibility in undertaking the future development of the South Timbalier 26 field.

We have included the results of operations from the acquisitions discussed above from their respective closing dates. We had experienced substantial revenue and production growth as a result of these acquisitions through the period prior to the tropical weather discussed below. For the foregoing reasons these acquisitions will affect the comparability of our historical results of operations with future periods.

On August 29, 2005 Hurricane Katrina made landfall south of New Orleans causing catastrophic damage throughout portions of the Gulf of Mexico and to portions of Alabama, Louisiana and Mississippi, including New Orleans. As a result of the devastating effects of the storm on New Orleans and surrounding areas, we announced on August 30 that we had elected to establish temporary headquarters at our Houston, Texas office. A satellite office was also established in Baton Rouge, Louisiana.

On September 24, 2005 Hurricane Rita made landfall in the United States on the Texas/Louisiana border between Sabine Pass, Texas and Johnson s Bayou, Louisiana. This hurricane caused extensive damage throughout portions of the region, particularly to third party infrastructure such as pipelines and processing plants.

As a result of these two major hurricanes and other Tropical Weather, nearly all of our production was shut in at one time or another during the third quarter of 2005 and a portion of that production had not yet been restored by the end of the fourth quarter of 2005. We are continuing to work to bring operations back to pre-storm levels, but are subject to constraints due to damage to third party infrastructure. During 2005 we maintained business interruption insurance on our significant properties, including our East Bay field. Recovery of lost revenue for our East Bay field and two other fields began accruing in October while recovery on a fourth field began accruing in December. Through December 31, 2005 we had accrued $20.6 million for business interruption. Production was fully restored

Table of Contents

in three of these fields in 2005, at which time coverage ceased, and recoveries will continue to accrue on one other until production is fully restored, subject to policy limits that we do not expect, at this time, to be reached.

Our revenue, profitability and future growth rate depend on a number of factors beyond our control, such as tropical weather, economic, political and regulatory developments and competition from 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 currently have an extensive inventory of drillable prospects in-house, we are generating more internally and we are being exposed to new opportunities through relationships with industry partners. Despite our expanded budget of $360 million in 2006, strong commodity prices, together with growing production volumes, should enable us to adhere to our policy of funding our exploration and development expenditures with internally generated cash flow. This strategy allows us to preserve our strong balance sheet to finance acquisitions and other capital intensive projects that might result from our exploration and development activities. We believe that the near term may provide us with further opportunities to acquire targeted properties, including those within our focus area.

Results of Operations

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

	Years Ended December 31,		
	2005	**2004**	**2003**
Net production (per day):			
Oil (Bbls)	7,984	8,663	7,978
Natural gas (Mcf)	88,430	82,098	78,596
Total (Boe)	22,722	22,346	21,077
Oil & natural gas revenues (in thousands):			
Oil	$ 135,359	$ 111,006	$ 81,599
Natural gas	266,646	183,525	148,104
Total	402,005	294,531	229,703
Average sales prices, net of hedging:			
Oil (per Bbl)	$ 46.45	$ 35.01	$ 28.02
Natural gas (per Mcf)	8.26	6.11	5.16
Total (per Boe)	48.47	36.01	29.86
Impact of hedging:			
Oil (per Bbl)	$ (3.15)	$ (4.40)	$ (1.67)
Natural gas (per Mcf)	(0.24)	(0.04)	(0.23)
Average costs (per Boe):			
Lease operating expense	$ 6.08	$ 4.93	$ 4.76
Taxes, other than on earnings	1.25	1.13	0.99
Depreciation, depletion and amortization	12.50	11.29	10.65
Increase in oil and natural gas revenue (net of hedging) due to:			
Change in prices of oil	$ 35,863	$ 22,160	
Change in production volumes of oil	(11,510)	7,247	
Total increase in oil sales	24,353	29,407	

Change in prices of natural gas	$ 64,006	$ 28,396
Change in production volumes of natural gas	19,115	7,025
Total increase in natural gas sales	83,121	35,421

Table of Contents

	As of December 31,		
	2005	**2004**	**2003**
Total estimated net proved reserves:			
Oil (Mbbls)	31,478	28,770	27,414
Natural gas (Mmcf)	166,949	149,835	134,404
Total (Mboe)	59,303	53,743	49,815
Present value of estimated future net cash flows before income taxes (in thousands)	$ 1,806,185	$ 924,135	$ 701,237
Standardized measure of discounted future net cash flows (in thousands)	$ 1,261,246	$ 667,668	$ 529,415

Revenues and Net Income

Our oil and natural gas revenues increased to $402.0 million in 2005 from $294.5 million in 2004. The increase in revenue for this period is in large part the result of sharply increased natural gas and oil prices which were driven even higher in the aftermath of Hurricanes Katrina and Rita. The increase was also attributable to increased production, despite the storms, resulting primarily from the commencement of production from 26 new wells brought on production since year end 2004, 23 of which were natural gas. In addition, our acquisitions in the first quarter of 2005 of the south Louisiana properties and the additional interest in South Timbalier 26 added incremental production compared to 2004. However, the foregoing increases were adversely impacted by an estimated 5,490 Boe per day of deferred production for the full year of 2005 from production shut-ins resulting from the Tropical Weather compared to deferred production of 597 Boe per day in 2004 from Hurricane Ivan and Tropical Storm Matthew. Also included in 2005 income from operations is $20.6 million of accrued business interruption insurance recoveries from deferred production at four of our fields resulting from Hurricanes Katrina and Rita.

Our oil and natural gas revenues increased to $294.5 million in 2004 from $229.7 million in 2003. In 2004, the oil and natural gas industry experienced then record high oil prices as well as sustained high natural gas prices. The increase in revenue for this period is the result of these significantly increased natural gas and oil prices combined with increased production resulting primarily from the commencement of production from 20 new wells brought on production since year end 2003, 16 of which were natural gas. These increases were partially offset by natural reservoir declines. In addition, volumes were negatively affected by Hurricane Ivan and Tropical Storm Matthew.

We recognized net income of $73.1 million in 2005 compared to net income of $46.4 million in 2004. The increase was primarily a result of the increase in oil and natural gas revenue and business interruption recovery previously discussed, which was offset by our increased operating costs, as discussed below. We recognized net income of $46.4 million in 2004 compared to net income of $33.3 million in 2003. The increase in net income in 2004 was primarily due to the increase in oil and natural gas revenues previously discussed and partially offset by higher operating costs, as discussed below.

While our 2005 results were strong, we did not achieve the sequential growth in volumes that we anticipated due to downtime from the Tropical Weather during the second half of the year.

Operating Expenses

Operating expenses were impacted by the following:

Lease operating expense increased $10.1 million to $50.4 million in 2005. The increase is a result of the uninsured portion of repairs due to the Tropical Weather of $2.7 million, and was also affected by new wells coming on stream in new fields, acquisitions during the first quarter of 2005 and workovers, as well as a general increase in the cost of oilfield industry services.

Lease operating expense increased $3.6 million to $40.3 million in 2004. This is a result of the addition of production from new fields and $1.0 million related to the retained loss portion of repairs due to Hurricane Ivan.

Table of Contents

Taxes, other than on earnings, increased $1.1 million to $10.4 million in 2005. This increase was due to the increase in commodity prices and production from the acreage acquired in the south Louisiana property acquisition. These taxes are expected to fluctuate from period to period depending on our production volumes from non-federal leases and the commodity prices received.

Taxes, other than on earnings increased $1.6 million to $9.3 million in 2004. This increase was due to the increase in commodity prices received for our oil and natural gas production on state leases, primarily at East Bay and Bay Marchand, which are subject to Louisiana severance taxes. These taxes are expected to fluctuate from period to period depending on our production volumes from state leases and the commodity prices received.

Exploration expenditures and dry hole costs, increased $35.9 million to $64.9 million in 2005. The increase is primarily due to the increase in our exploratory drilling program from 25 exploratory wells drilled in 2004, to 45 exploratory wells drilled in 2005. The expense in 2005 is comprised of $52.0 million of costs for exploratory wells or portions thereof which were found to be not commercially productive and $12.9 million of seismic expenditures and delay rentals.

Exploration expenditures increased $14.4 million to $29.0 million in 2004. The expense in 2004 was comprised of $21.0 million of costs for exploratory wells or portions thereof which were found to be not commercially productive and seismic expenditures and delay rentals of $8.0 million.

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

Impairment of properties increased $11.0 million to $17.9 million in 2005. The increase is due to impairments taken at six fields which would need significant capital to extend their economic lives. We decided to deploy the capital to projects with more potential, therefore impairing the assets. We also had two fields with partial impairments due to insufficient cash flow from reserves.

Impairment of properties increased $4.1 million to $6.9 million in 2004. The expense in 2004 was comprised of a property impairment at our East Cameron 378 field.

Depreciation, depletion and amortization increased $11.2 million to $103.6 million in 2005. The increase was in part a result of higher production in 2005. In addition, the shift in the production contribution amongst our various fields increased our total expense as well as our expense per Boe. Some fields carry a higher depreciation burden than others, therefore, changes in the mix of our production among the various fields will directly impact this expense.

Depreciation, depletion and amortization increased $10.5 million to $92.4 million in 2004. The increase was due to the increased depreciable asset base combined with higher production and a shift in the production contribution from our various fields. This expense includes $6.6 million of amortization for our asset retirement obligation for 2004 as compared to $5.2 million in 2003. In addition, the shift in the production contribution amongst our various fields increased our expense per Boe. Some fields carry a higher depreciation burden than others, therefore, changes in the mix of our production among the various fields will directly impact this expense.

Other general and administrative expenses increased $8.5 million to $36.4 million in 2005. The increase was due to the provision for a contractual dispute of $3.4 million as well as the costs associated with temporarily relocating our personnel and headquarters to Houston and opening a Baton Rouge office in the wake of Hurricane Katrina. Costs incurred of approximately $1.6 million included employee relocation allowances and housing, temporary office space and furniture rental as well as the purchase of computer equipment. In addition, the increase was due to increased personnel costs resulting from our overall increased level of activity and expanded asset base as well as increased cost of insurance.

Other general and administrative expenses increased $1.2 million to $27.9 million in 2004. The increase was primarily due to increased consulting costs of $1.9 million, of which $0.4 million was increased costs paid to our internal audit service provider and external auditors to implement the requirements of Section 404 of the

Table of Contents

Sarbanes-Oxley Act of 2002. The remainder included increased human resources, land and engineering consulting costs which was offset by decreased casualty insurance and technology costs.

Non-cash stock-based compensation expense of $6.8 million was recognized in 2005, an increase of $3.7 million from 2004. The increased expense relates to the increased amortization of new restricted share units and performance share awards made to employees in late 2004 and in 2005 as well as the impact of the increased stock price throughout most of the year on our variable awards and accelerated vesting of stock awards for two former employees.

Non-cash stock-based compensation expense of $3.1 million was recognized in 2004, an increase of $1.8 million from 2003. This expense has increased due to additional grants of restricted share units and performance share awards to employees. The level of expense for these awards is also affected by the increased stock price in 2004.

Other Income and Expense

Interest expense increased $3.7 million to $18.1 million in 2005. The increase was a result of interest expense on borrowings under our bank credit facility to finance acquisitions and for short-term fluctuations in working capital.

Interest expense increased $4.2 million to $14.4 million in 2004. The increase was a result of interest expense on the Senior Notes issued in August 2003 partially offset by the interest savings from the redemption of the 11% Notes and the repayment of borrowings under the bank facility in 2003.

Financial Condition, Liquidity and Capital Resources

The trend of increased revenues we have experienced in 2005 has continued to provide strong cash flows from operations, which totaled $270.0 million. We intend to fund our exploration and development expenditures from internally generated cash flows, which we define as cash flows from operations before consideration of changes in working capital plus total exploration expenditures. Our cash on hand at December 31, 2005 was $6.8 million. Our future internally generated cash flows will depend on our ability to maintain and increase production through our exploration and development drilling program, as well as the prices of oil and natural gas. We may from time to time use the availability of our bank credit facility to balance working capital needs.

Our bank credit facility, as amended on August 3, 2004, consists of a revolving line of credit with a group of banks available through August 3, 2008 (the bank credit facility). The bank credit facility currently has a borrowing base of $150 million that is subject to redetermination based on the proved reserves of the oil and natural gas properties that serve as collateral for the bank credit facility as set out in the reserve report delivered to the banks each April 1 and October 1. The bank credit facility permits both prime rate borrowings and London interbank offered rate (LIBOR) borrowings plus a floating spread. The spread will float up or down based on our utilization of the bank credit facility. The spread can range from 1.25% to 2.00% above LIBOR and 0% to 0.75% above prime. The borrowing base under the bank credit facility is secured by substantially all of our assets. We used our bank credit facility to fund a portion of the purchase of the south Louisiana properties in January 2005 and the acquisition of the additional interest in South Timbalier 26 in March 2005. At February 22, 2006, we had $95 million outstanding and $55 million of credit capacity available under the bank credit facility. In addition, we pay an annual fee on the unused portion of the bank credit facility ranging between 0.375% to 0.5% based on utilization. The bank credit facility contains customary events of default and various financial covenants, which require us to: (i) maintain a minimum current ratio, as defined by our bank credit facility, of 1.0 and (ii) maintain a minimum EBITDAX to interest ratio, as defined by our bank credit facility, of 3.5 times. We were in compliance with these covenants as of December 31, 2005.

On August 5, 2003, we issued $150 million of 8.75% senior notes due 2010 which were exchanged in October 2003 for registered 8.75% senior notes due 2010 (the Registered Senior Notes) with substantially the same terms. The Registered Senior Notes bear interest at a rate of 8.75% per annum with interest payable semi-annually on February 1 and August 1, beginning February 1, 2004. We may redeem the Senior Notes at our option, in whole or in part, at any time on or after August 1, 2007 at a price equal to 100% of the principal amount plus accrued and unpaid interest, if any, plus a specified premium which decreases yearly from 4.375% in 2007 to 0% in 2009 and thereafter. In addition, at any time prior to August 1, 2006, we may redeem up to a maximum of 35% of the aggregate principal amount with the net proceeds of certain equity offerings at a price equal to 108.75% of the principal amount, plus accrued and unpaid interest. The notes are unsecured obligations and rank equal in right of payment to all existing and future senior debt, including the bank credit facility, and will rank senior or equal in right of payment to all existing and future subordinated indebtedness. The indenture relating to the Registered Senior Notes contains certain restrictions on our ability to incur additional debt, pay dividends on our common stock, make investments, create liens on our assets, engage in transactions with our affiliates, transfer or sell assets and consolidate or merge substantially all of our assets. The Registered Senior Notes are not subject to any sinking fund requirements.

Upon closing on the Senior Notes on August 5, 2003, we called our 11% Notes due 2009 for redemption. The redemption of the 11% Notes in aggregate principal and accrued interest was funded with a portion of the proceeds received from the Senior Notes and was completed in August 2003. The 11% Notes were issued on January 15, 2002 as part of the financing of an acquisition. In addition, $39.9 million of the proceeds from the Senior Notes were used to re-pay substantially all of the borrowings under the bank credit facility. As a result of the issuance of the Senior Notes, our bank credit facility borrowing base was reduced from $100 million to $60 million requiring a non-cash charge of $0.3 million for the write-off of the pro rata remaining balance of unamortized issue costs.

Net cash of $449.2 million used in investing activities in 2005 primarily included $254.9 million of oil and natural gas property capital and exploration expenditures and $193.1 million for property acquisitions which included the acquisitions of properties and reserves onshore in south Louisiana, the acquisition of the remaining 50% gross working interest in South Timbalier 26 and $27.6 million of lease acquisitions. Exploration expenditures incurred are excluded from operating cash flows and included in investing activities. During 2005, we completed 56 drilling projects and 32 recompletion/workover projects, 60 of which were successful. During 2004, we completed 31 drilling projects and 21 recompletion/workover projects, 41 of which were successful.

Our 2006 capital exploration and development budget is focused on exploration, exploitation and development activities on our proved properties combined with moderate and higher risk exploratory activities on undeveloped leases and does not include acquisitions. We continue to manage our portfolio in order to maintain an appropriate risk balance between low risk development and exploitation activities, moderate risk exploration opportunities and higher risk, higher potential exploration opportunities. Our exploration and development budget for 2006 is currently $360 million. We do not budget for acquisitions. During 2005, capital and exploration expenditures were approximately $485.7 million inclusive of a $0.9 million contingent consideration payment resulting from an acquisition completed during 2002, $170.5 million related to acquisitions in 2005 and $6.9 million in asset retirement obligations. The level of our budget is based on many factors, including results of our drilling program, oil and natural gas prices, industry conditions, participation by other working interest owners and the costs of drilling rigs and other oilfield goods and services. Should actual conditions differ materially from expectations, some projects may be accelerated or deferred and, consequently, may increase or decrease total 2006 capital expenditures.

We have experienced and expect to continue to experience substantial working capital requirements, primarily due to our active exploration and development program. We believe that internally generated cash flows will be sufficient to meet our budgeted capital requirements for at least the next twelve months. Availability under the bank facility will be used to balance short-term fluctuations in working capital requirements. However, additional financing may be required in the future to fund our growth.

Table of Contents

Disclosures about Contractual Obligations and Commercial Commitments

The following table aggregates the contractual commitments and commercial obligations that affect our financial condition and liquidity position as of December 31, 2005:

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	Thereafter
	(In thousands)				
Long-term debt	$ 235,109	$ 109	$ 85,000	$ 150,000	$
Interest attributable to all long-term debt	68,231	18,282	29,258	20,781	
Operating leases	17,764	3,074	4,161	2,826	7,703
Unconditional purchase obligations(1)	58,367	52,367	6,000		
Other long-term liabilities	11,213		9,842		1,371
Total contractual obligations	$ 390,684	$ 73,832	$ 134,261	$ 173,607	$ 9,074

(1) Consists of commitments to purchase seismic related services and drilling rig commitments.

Off-Balance Sheet Transactions

We do not maintain any off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities or others that are reasonably likely to have a material current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Hedging Activities

We enter into hedging transactions with major financial institutions to reduce exposure to fluctuations in the price of oil and natural gas. We also distribute our hedging transactions to a variety of financial institutions to reduce our exposure to counterparty credit risk. Our hedging program uses financially-settled crude oil and natural gas swaps and zero-cost collars to provide floor prices with varying upside price participation. Our hedges are benchmarked to the New York Mercantile Exchange (NYMEX) West Texas Intermediate crude oil contracts and Henry Hub natural gas contracts. With a financially-settled swap, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the hedged price for the transaction, and we are required to make a payment to the counterparty if the settlement price for any settlement period is above the hedged price for the transaction. With a zero-cost collar, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price of the collar, and we are required to make a payment to the counterparty if the settlement price for any settlement period is above the cap price of the collar. In some hedges, we may modify our collar to provide full upside participation after a limited non-participation range. We had no crude oil positions and the following natural gas contracts as of December 31, 2005:

Natural Gas Positions		
	Strike Price	Volume (Mmbtu)

Remaining Contract Term	Contract Type	($/Mmbtu)	Daily	Total
01/06 - 12/06	Collar	$ 5.00/$9.51	15,000	5,475,000
01/07 - 12/07	Collar	$ 5.00/$8.00	10,000	3,650,000

Accounting and reporting standards require that derivative instruments, including certain derivative instruments embedded in other contracts, be recorded at fair market value and included as either assets or liabilities in the balance sheet. The accounting for changes in fair value depends on the intended use of the derivative and the resulting designation, which is established at the inception of the derivative. Special accounting for qualifying hedges allows a derivative s gains and losses to offset related results on the hedged item in the statement of operations. For derivative instruments designated as cash-flow hedges, changes in fair value, to the extent the hedge

Table of Contents

is effective, will be recognized in other comprehensive income (a component of stockholders equity) until the forecasted transaction is settled, when the resulting gains and losses will be recorded in oil and natural gas revenue. Hedge ineffectiveness is measured at least quarterly based on the changes in fair value between the derivative contract and the hedged item. Any change in fair value resulting from ineffectiveness is charged currently to other revenue.

Our hedged volume as of December 31, 2005 approximated 8% of our estimated production from proved reserves through the balance of the terms of the contracts.

We may in the future enter into these and other types of hedging arrangements to reduce our exposure to fluctuations in the market prices of oil and natural gas. Hedging transactions expose us to risk of financial loss in some circumstances, including if production is less than expected, the other party to the contract defaults on its obligations, or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. Hedging transactions may limit the benefit we would have otherwise received from increases in the prices for oil and natural gas. Furthermore, if we do not engage in hedging transactions, we may be more adversely affected by declines in oil and natural gas prices than our competitors who engage in hedging transactions.

Discussion of Critical Accounting Policies

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

Successful Efforts Method of Accounting Oil and natural gas exploration and production companies choose one of two acceptable accounting methods, successful-efforts or full cost. The most significant difference between the two methods relates to the accounting treatment of drilling costs for unsuccessful exploration wells (dry holes) and exploration costs. Under the successful-efforts method, we recognize exploration costs and dry hole costs as an expense on the income statement when incurred and capitalize the costs of successful exploration wells as oil and natural gas properties. Companies that follow the full cost method capitalize all drilling and exploration costs including dry hole costs into one pool of total oil and natural gas property costs.

We use the successful-efforts method because we believe that it more conservatively reflects, on our balance sheet, the historical costs that have future value. However, using successful-efforts often causes our income to fluctuate significantly between reporting periods based on our drilling success or failure during the periods.

It is typical for companies that have an active exploratory drilling program, as we do, to incur dry hole costs. During the last three years we have drilled 91 exploration wells, of which 26 were considered dry holes. Our dry hole costs charged to expense during this period totaled $82.9 million out of total exploratory drilling costs of $345.3 million. It is impossible to predict future dry holes; however we expect to continue to have dry hole costs in the future which will vary depending on the amount of our capital dedicated to exploration activities and on the level of success of our exploratory program.

Proved Reserve Estimates Evaluations of oil and natural gas reserves are important to the effective management of our producing assets. They are integral to making investment decisions and are also used as a basis of calculating the units of production rates for depletion, depreciation and amortization and evaluating capitalized costs for impairment. Proved reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made.

Our independent reserve engineers prepare our oil and natural gas reserve estimates using guidelines established by the U.S. Securities and Exchange Commission and U.S. generally accepted accounting principles. The quality and quantity of data, the interpretation of the data, and the accuracy of mandated economic assumptions combined with the judgment exercised by the independent reserve engineers affect the accuracy of the estimated reserves. In addition, drilling or production results after the date of the estimate may cause material revisions to the reserve estimates in subsequent periods.

At December 31, 2005, proved oil and natural gas reserves were 59.3 million barrels of oil-equivalent (Mmboe). Approximately 82% of our proved reserves are classified as either proved undeveloped or proved developed non-producing reserves. Most of our proved developed non-producing reserves are behind pipe and will be produced after depletion of another horizon in the same well. Approximately 28% of total proved reserves are categorized as proved undeveloped reserves. As of December 31, 2005, 47% of our proved undeveloped reserves were under development and expected to become proved developed within one year.

You should not assume that the present value of the future net cash flow disclosed in this report reflects the current market value of the oil and natural gas reserves. In accordance with the U.S. Securities and Exchange Commission s guidelines, we use prices and costs determined on the date of the estimate and a 10% discount rate to determine the present value of future net cash flow. Actual costs incurred and prices received in the future may vary significantly and the discount rate may or may not be appropriate based on outside economic conditions.

The computation of the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves at December 31, 2005 was based on period-end prices of $10.31 per Mcf for natural gas and $57.81 per barrel for crude after adjusting the West Texas Intermediate posted price per barrel and the Gulf Coast spot market price per Mmbtu for energy content, quality, transportation fees, and regional price differentials for each property. We estimated the costs based on the current year costs incurred for individual properties or similar properties if a particular property did not have production during the prior year.

Depletion, Depreciation, and Amortization of Oil and Natural Gas Properties We calculate depletion, depreciation, and amortization expense (DD&A) using the estimates of proved oil and natural gas reserves previously discussed in these critical accounting policies. We segregate the costs for individual or contiguous properties or projects and record DD&A for these property costs separately using the units of production method. The units of production method is calculated as the ratio of (1) actual volumes produced to (2) total proved developed reserves (those proved reserves recoverable through existing wells with existing equipment and operating methods) applied to (3) asset cost. The volumes produced and asset cost are known, and while proved developed reserves are reasonably certain, they are based on estimates that are subject to some variability. This variability can result in net upward or downward revisions of proved developed reserves in existing fields, as more information becomes available through research and production and as a result of changes in economic conditions. Our revisions over the three years prior to the 2005 fiscal year, in each case either positive or negative, had been less than 5% of total proved reserves on a barrel of oil equivalent basis, however in 2005 our negative revisions of 4,045 Mboe represented 7.5% of our total reserves. These revisions included a downward revision of 5,351 Mboe primarily related to the proved undeveloped reserves acquired in the South Louisiana onshore acquisition in January 2005. Such revisions were derived primarily from the results of actual drilling activity in 2005. While the revisions we have made in the past are an indicator of variability, they have had a minimal impact on the units of production rates because they have been low compared to our reserve base or relate to fields just coming on production. Actual historical revisions are not necessarily indicative of future variability.

Impairment of Oil and Natural Gas Properties We continually monitor our long-lived assets recorded in property and equipment in our consolidated balance sheet to make sure that they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset may not be recoverable. Because we account for our proved oil and natural gas properties separately under the successful efforts method of accounting, we assess our assets for impairment property by property rather than in one pool of total oil and natural gas property costs. A significant amount of judgment is involved in performing these evaluations since the amount is based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the ultimate amount of recoverable oil and natural gas reserves that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas, and future inflation levels. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserve volumes, or other changes to contracts, environmental regulations or tax laws. In general, we do not view temporarily low oil or natural gas prices as a triggering event for conducting impairment tests. The markets for crude oil and natural gas have a history of significant price volatility. Although prices will occasionally drop precipitously, industry prices over the long-term are driven by market supply and demand. Accordingly, any impairment tests that we perform make use of our long-term price assumptions for the crude oil and natural gas markets.

We base our assessment of possible impairment using our best estimate of future prices, costs and expected net cash flow generated by a property. We estimate future prices based on management s expectations and escalate both the prices and the costs for inflation if appropriate. If these undiscounted estimates indicate an impairment, we measure the impairment expense as the difference between the net book value of the asset and its estimated fair value measured by discounting the future net cash flow from the property at an appropriate rate. Actual prices, costs, discount rates, and net cash flow may vary from our estimates. An estimate as to the sensitivity to earnings resulting from impairment reviews and impairment calculations is not practicable, given the broad range in the cost structure of our oil and natural gas assets and the number of assumptions involved in the estimates. That is, favorable changes to some assumptions may avoid the need to impair any assets, whereas unfavorable changes might cause some assets to become impaired but not others. We recognized impairment expense of $17.9 million, $6.9 million and $2.8 million in the years ending December 31, 2005, 2004 and 2003. The impairment in 2005 consisted of full impairment at six fields which we determined would need significant capital to extend their economic lives. We decided that the capital would be deployed to projects with more potential and therefore impaired the assets. Additionally, we had two fields with partial impairmen