ENERGY PARTNERS LTD
Form 10-K
February 27, 2006

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

Registrant s telephone number, including area code:
504-569-1875

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

Title of Each Class	**Name of Exchange on Which Registered**
Common Stock, Par Value $0.01 Per Share	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.

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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

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.

(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.

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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.

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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

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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.

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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

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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 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

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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;

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- 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

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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

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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.

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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

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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.

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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**