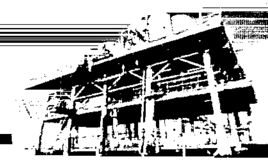
# EPL 2003

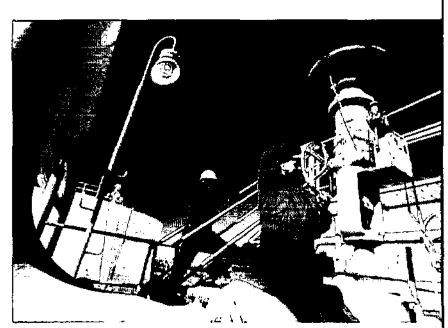
# CONTINUING MOMENTUM



## ENERGY PARTNERS, LTD.

# STRENGTH GAINED BY ACTION

Energy Partners, Ltd. (EPL) is an independent oil and natural gas exploration and production company concentrated in the shallow to moderate depth waters of the Gulf of Mexico Shelf. Since our inception in 1998, we have focused on this area because it provides us with favorable geologic and economic conditions and an extensive array of exploration, exploitation and development opportunities. In 2003, we achieved the best operational and financial results in our history. This report highlights our 2003 successes and discusses our strategy to continue the momentum we have established in creating value.



**BY ALL MEASURES,** 2003 was a landmark year for EPL. We reported the highest revenues, net income and discretionary cash flow in our five-year history; we executed the most extensive exploratory drilling program since our inception and maintained our significantly better-than-industry-average success rate; we grew our production 23% to a new record high without any benefit from acquisitions; we replaced 130% of that expanded production with new reserves, again with no benefit from acquisitions, at an attractive average cost of $11.19 per Boe; we made continued progress in reducing our per-unit operating costs; and, through a series of well-executed financial market transactions, we significantly strengthened our balance sheet and increased the public float of our common stock. The team effort of our operational and financial staffs led to this exceptional success.

At the beginning of last year, our Board approved an initial 2003 capital and exploration budget of $90 million, up 32% from the actual amount spent in 2002. It was our intent to match our capital investment program as closely as possible with our cash flow generation, retaining flexibility to increase or reduce our budget with changes in commodity prices. For the first half of 2003, we devoted the greater part of our efforts to developing the nine exploratory successes we drilled in the latter part of 2002. By mid-year 2003, we had initiated production at eight new wells, giving us a good start on what was shaping up to be a record year for production. Late in the second quarter, we ramped up our 2003 exploratory drilling program.

Even as we were busy on the drilling and operational fronts, we were also focusing our attention on the financial side of our business. In April we launched a combined primary and secondary offering of EPL's common stock. We undertook the primary portion of the offering to provide us with additional financial capacity to act quickly on strategic property acquisitions. While we pride ourselves on our extensive inventory of drilling opportunities, we continue to view acquisitions as a key component in our overall growth strategy. Since our inception, organic growth from the drill-bit has replaced 134% of our production while acquisitions have replaced 173% of our production. The April equity offering generated net proceeds of $37.5 million for the Company, which was used to repay a portion of the outstanding debt on our credit facility. The secondary portion of the offering enabled two of our original private equity providers to liquidate a portion of their investment. To further improve our financial flexibility, in July we successfully completed a debt offering which consisted of $150 million in 8 3/4%

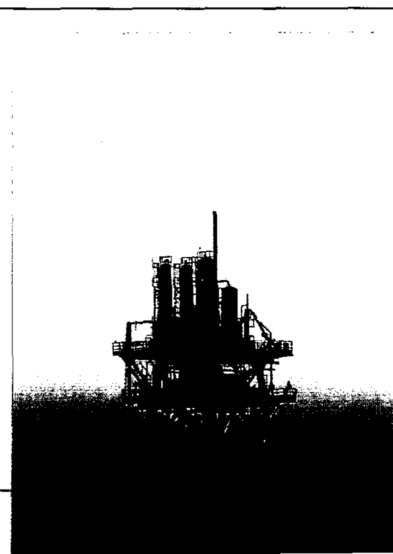

WORKING AS ONE

Senior Unsecured Notes. With the proceeds from that offering, we redeemed all of the outstanding 11% Senior Subordinated Notes due 2009 issued in conjunction with the Hall-Houston acquisition in 2002 and paid off substantially all of the remaining balance on our credit facility. After all debt paydown, we retained nearly $67 million of the proceeds in cash. The cash, in combination with our nearly $60 million of unused capacity under our credit facility, provides us with significant dry powder in our search for the right acquisition.

In July, while commodity prices remained strong and our portfolio of drilling opportunities continued to grow, we increased our capital budget to $110 million. By year-end, we had completed drilling 21 exploratory wells, with 12 of those decisioned in the fourth quarter alone. We are very proud that in the busiest drilling year ever at EPL, we maintained our historically high success rate on exploratory drilling, with 17 successes out of 21 wells drilled. The success of that program was evident in the strong results we reported for the year in terms of reserve replacement and finding and development costs. At year-end 2003, our proved reserves grew to 49.8 Mmboe, up 5% from the prior year-end. It is important to note that our proved reserve estimates are based upon third party engineering reports prepared by Netherland, Sewell & Associates and Ryder Scott Company, L.P.

Our successful drilling program in both 2002 and 2003 led to a significant rise in production in 2003. Total production averaged 21,077 Boe per day, a new record high, up 23% from our 2002 average of 17,173 Boe per day. Natural gas accounted for a larger percentage of our production, rising to 62% of total production compared with 53% in 2002. At the same time we grew production, we also lowered our per-unit operating costs. Lease operating expense fell to $4.77 per Boe in 2003, from $5.49 in 2002 and $6.21 in 2001.

This marked improvement in costs can be directly traced to the efforts of our operational and production staffs. They continue to find ways to optimize production and control costs while remaining focused on maintaining the highest of safety standards. As a testament to that effort, EPL was



recently named a recipient of the Minerals Management Service's "Safety Award for Excellence" for our East Bay operations. This award is given annually to recognize companies that achieve superior results in conducting operations in a safe and pollution free manner. I am particularly proud that we are the youngest company to receive this recognition from the New Orleans District office of the Minerals Management Service. We are also the first operator of the East Bay field throughout its 55 years of history to ever receive this award.

In addition to our outstanding operational performance in 2003, we reported record financial results. Revenues grew 72% to $230.2 million from $133.8 million in 2002. We reported operating income of $58.6 million in 2003 compared with an operating loss of $6.6 million in 2002, while our net income for 2003 totaled $33.3 million compared with a net loss of $8.8 million in 2002. This dramatic improvement in results was primarily attributable to higher production volumes and continued strong commodity prices.

Our ability to quickly initiate production from our exploratory successes and achieve high rates of production on those wells generates attractive returns on our invested capital. For 2003, our return on average capital employed was 19% and our five-year average was 16%. The key to our continued ability to create value will be in the successful reinvestment of our growing cash flow in similar new projects. We believe we have the leadership, the prospect inventory, and the risk profile to repeat that performance in 2004.

We have set our 2004 capital and exploration budget at $125 million, up 14% from the 2003 budget. We plan to drill between 26 and 30 exploratory wells and 8 to 12 development wells. From a risk standpoint, our 2004 exploratory program will look very much like the 2003 program. And just like last year, we intend to fully fund that plan with internally generated funds and will review it periodically to adjust for material commodity price fluctuations and new drilling opportunities. Our budget does not, however, include funds for acquisitions, which will be financed with our strong balance sheet. While we have looked at many potential acquisitions, none yet have fit our criteria on price, exploratory upside, and size. We are continuing to pursue acquisitions, recognizing that diligence and patience are required to find a package that delivers value to our shareholders. We are hopeful that 2004 will present us with the right opportunity.

Significant changes occurred in our shareholder base during 2003. Evercore, which provided us with significant equity funding in 1999 when we were a private company, liquidated their entire stake in EPL common stock through a series of offerings during 2003. By year-end, 80% of our common stock was held in public hands compared with 39% at the beginning of the year. As a result, our average common stock trading volume has increased more than six-fold. We are now well positioned to attract the full range of institutions into investing in our Company's stock.

Following the sale of Evercore's stock, Austin Beutner, President and Co-Founder of Evercore, who had been a member of our Board since their equity investment, resigned his position on our Board. I would like to personally thank Austin for his four years of dedicated service to EPL; his experience, energy, knowledge, and sage counsel made him a valuable Board member and counsel to me. Evercore was an excellent partner to EPL as we evolved from a small private company to a growing mid-sized E&P company.

I would also like to welcome two new Board members. In March of 2003, we expanded our Board to 10 members with the appointment of Jerry Carlisle, who subsequently was named Chairman of our Audit Committee. Jerry's 30-plus years of financial management, public accounting and educational leadership will serve us well. Recently Enoch Dawkins was named to our Board to fill the vacancy created with Austin's departure. Enoch is the retired President of Murphy Exploration and

Production Company. His 40 years of experience in our sector of the energy industry should prove valuable to us as we pursue our drilling and acquisition strategy.

In closing, I want to again acknowledge the dedication and hard work of all our employees. Their ability to work together as one team focused on creating value allowed us to achieve the best year in our history, both operationally and financially. We enter 2004 poised for growth. Our expanded exploratory program is well underway and we have a strong balance sheet that gives us the flexibility to act quickly to seize opportunities as they arise. As an organization, we are executing on all fronts, and we are looking to continuing that momentum into 2004.

Richard A. Bachmann
Founder, Chairman, President and
Chief Executive Officer

## FINANCIAL DATA

| (In thousands, except price and per share amounts) | 2003 | 2002 | 2001 | 2000 | 1999 |
|---|---|---|---|---|---|
| Revenues | $ 230,187 | $ 133,788 | $ 146,240 | $ 111,017 | $ 9,509 |
| Income (loss) from operations (a) | 58,560 | ($6,600) | 20,663 | (940) | (835) |
| Net income (loss) | 33,250 | (8,799) | 11,974 | (18,684) | (2,284) |
| Diluted earnings (loss) per common share (b) | $ 0.93 | $ (0.44) | $ 0.44 | $ (2.27) | $ (0.22) |
| Diluted weighted average common shares | 35,575 | 27,467 | 26,920 | 11,160 | 14,247 |
| Total finding and development costs | 111,882 | 68,066 | 103,467 | 63,116 | 17,112 |
| Total assets | $ 544,181 | $ 384,220 | $ 242,777 | $ 208,149 | $ 69,276 |
| Long-term debt | 150,416 | 103,779 | 25,493 | 100 | 10,150 |
| Mandatorily redeemable preferred stock | — | — | — | — | 56,475 |
| Stockholders' equity | 261,485 | 191,922 | 164,867 | 150,591 | (3,815) |

## OPERATING DATA

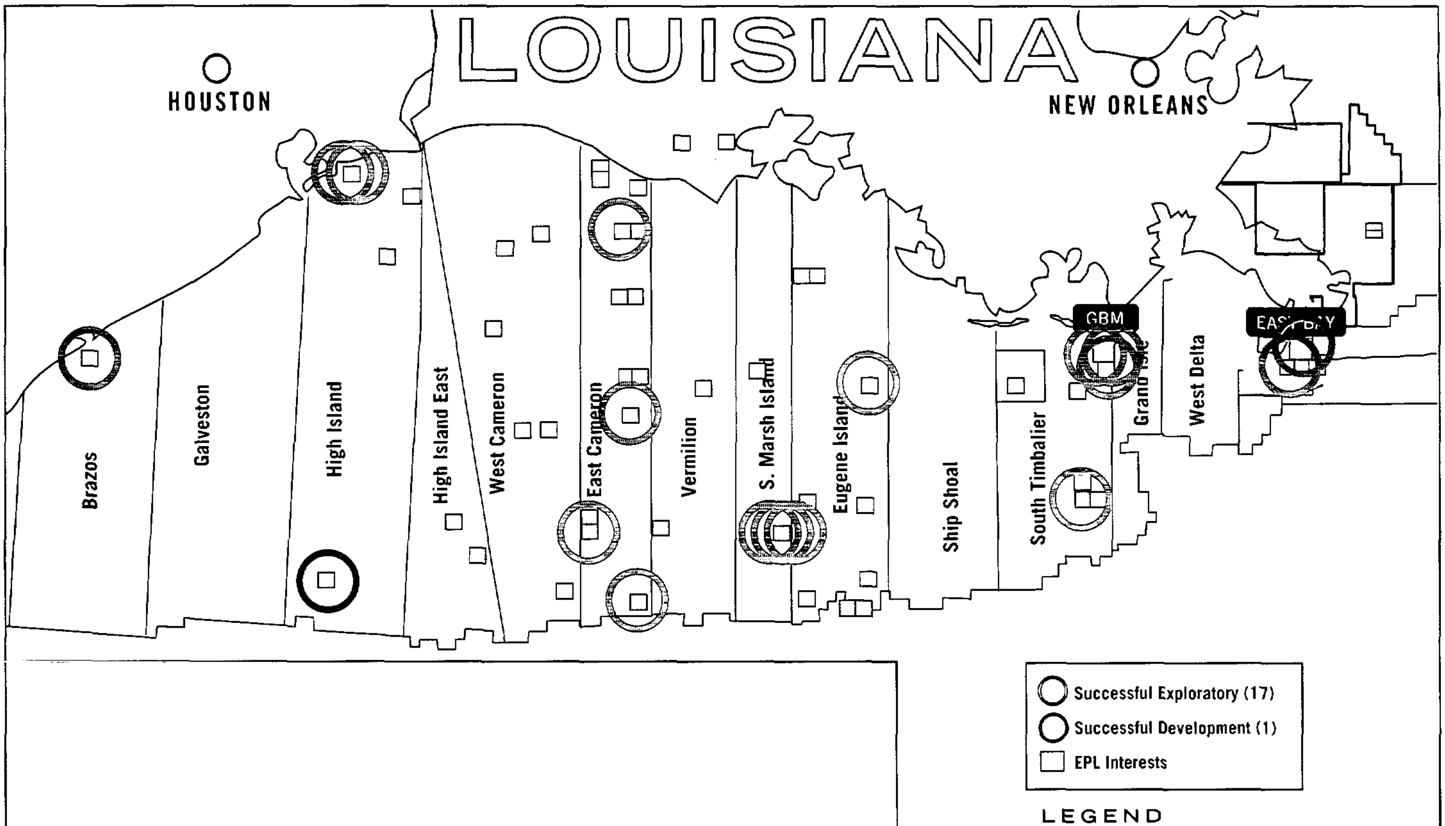
| | 2003 | 2002 | 2001 | 2000 | 1999 |
|---|---|---|---|---|---|
| Total estimated net proved reserves: | | | | | |
| Oil (Mbbls) | 27,414 | 26,353 | 25,462 | 27,521 | 3,824 |
| Natural gas (Mmcf) | 134,404 | 126,957 | 61,797 | 49,150 | 12,752 |
| Total (Mboe) | 49,815 | 47,513 | 35,762 | 35,712 | 5,949 |
| Net production (per day): | | | | | |
| Oil (Bbls) | 7,978 | 8,148 | 10,358 | 7,622 | 1,051 |
| Natural gas (Mcf) | 78,596 | 54,150 | 34,562 | 15,781 | 2,277 |
| Total (Boe) | 21,077 | 17,173 | 16,118 | 10,252 | 1,431 |
| Average sales price:(c) | | | | | |
| Oil (per Bbl) | $ 28.02 | $ 23.64 | $ 23.44 | $ 25.86 | $ 17.39 |
| Natural gas (per Mcf) | 5.16 | 3.23 | 4.40 | 4.98 | 2.17 |
| Total (per Boe) | 29.86 | 21.40 | 24.50 | 26.89 | 16.22 |
| Present value of estimated future net revenues before income taxes (in thousands)(d) | $ 701,237 | $ 608,273 | $ 129,122 | $ 489,945 | $ 54,819 |
| Total well projects | 56 | 44 | 88 | 108 | 20 |
| Percentage of successful well projects | 82% | 77% | 86% | 91% | 75% |

(a) The 2000 loss from operations includes a one time non-cash stock compensation charge for shares released from escrow to management and director stockholders of $38.2 million and non-cash charge of $2.1 million for bonus shares awarded to employees at the time of the initial public offering. The after-tax amount of these charges totaled $39.5 million. Although these charges reduced our net income, they increased paid-in-capital, and thus did not result in a net reduction of total stockholders' equity.

(b) Net earnings (loss) per share is computed by subtracting preferred stock dividends and accretion of discounts of $3.3 million in 2002 and preferred stock dividends and accretion of issuance costs for the years ended December 31, 2000 of $6.7 million and December 31, 1999 of $0.8 million.

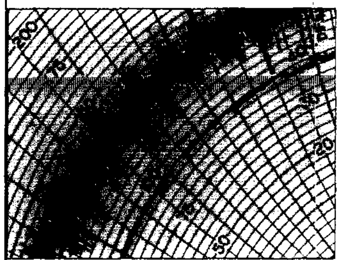
(c) Net of the effect of hedging transactions.

(d) 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.




# MAINTAINING FOCUS

In 2003, EPL continued to focus its drilling program on the Gulf of Mexico Shelf and again achieved excellent results. We drilled 23 new wells, 21 of which were exploratory prospects and two of which were development locations. 17 of the 21 exploratory wells were successful, for an 81% success rate. One of the two development wells was successful, for an overall drilling success rate of 78%. EPL's successes spanned a broad area of the Gulf of Mexico Shelf, from East Bay and South Pass in the east to Brazos in the west, all in less than 500 feet of water. They included a mix of low risk development and exploitation opportunities along with moderate risk and higher risk, higher potential exploratory plays. The map above outlines EPL's acreage position and highlights our drilling successes in 2003.



# STRATEGIC REVIEW

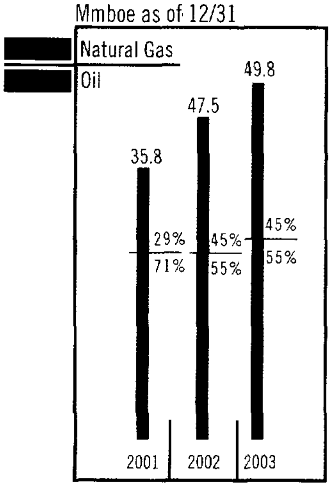
**IN 2003,** our operational success was highlighted with an 81% success rate in our exploratory drilling program, a 23% growth in our production volumes and a 10% reduction in our per-unit cash operating costs.

During 2003, we drilled 21 exploratory wells of which 17 were successful, achieving a better-than-industry-average success rate of 81%. Approximately half of the exploratory prospects drilled were from the inventory we held at the beginning of the year and half came from new sources during the year, including lease sales and opportunities offered to us by industry partners. Seven of these discoveries were onstream by the end of the year, five are expected onstream in the first half of 2004, and the remaining five successes are expected to come online in the second half of 2004. We operated 11, or 65%, of the successful exploratory wells and our average working interest in the successful wells was approximately 50%. We also drilled two development wells during the year, one of which was successful. In addition, we successfully completed 28 workovers and recompletions of existing wells.

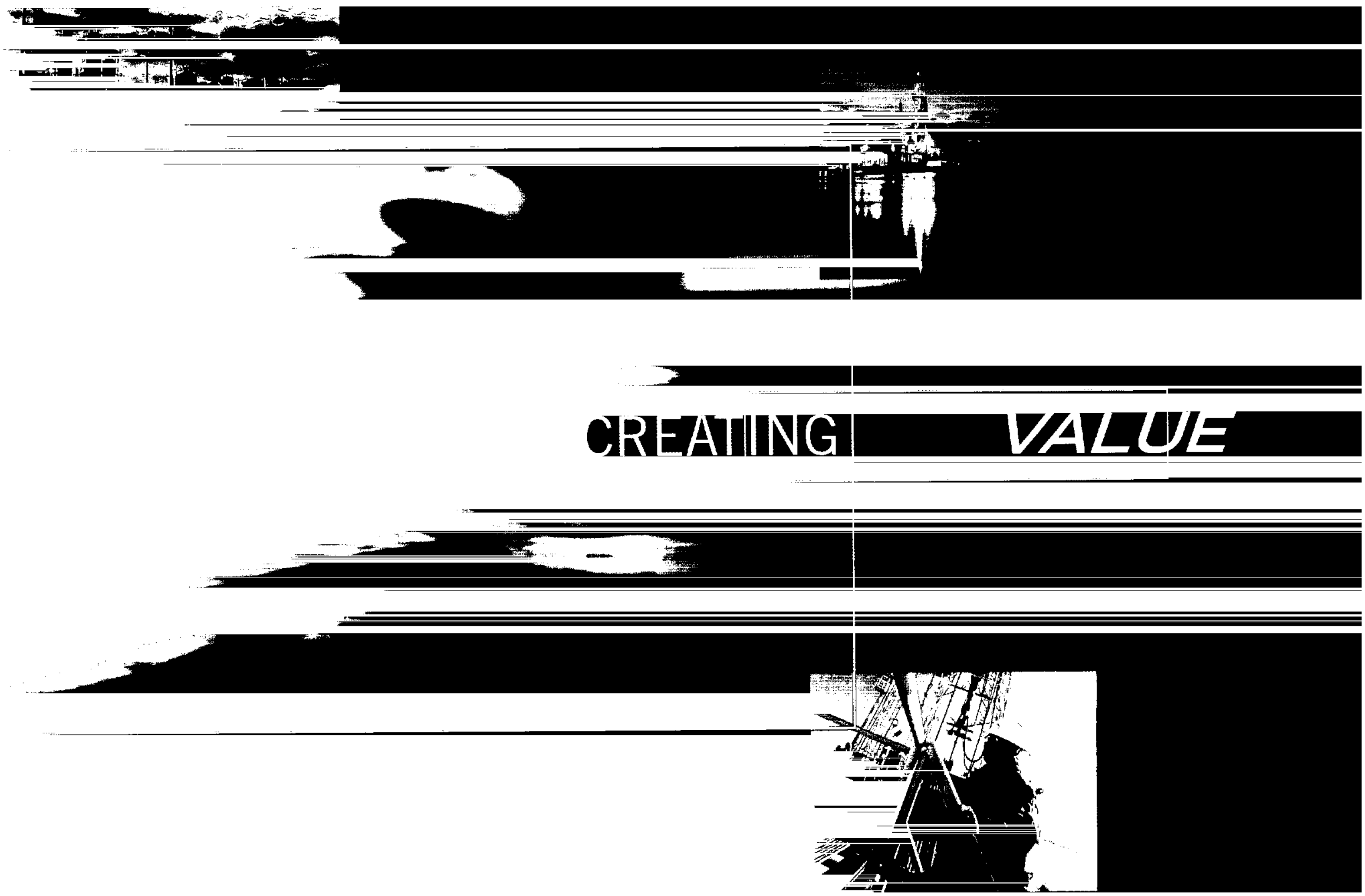
Our drilling program in 2003 replaced 130% of the year's production. All of the reserves added were achieved through the drill-bit as there were no acquisitions of reserves during the year. Drill-bit replacement of 130% is in-line with our average drill-bit replacement since the inception of the Company of 134%. Total proved reserves at year-end 2003 were 49.8 Mmboe, up 5% from the prior year-end. Reserves were 45% natural gas and 55% oil, with 69% classified as proved developed reserves. Our reserve life at year-end 2003 was 6.5 years.

Finding and development costs for 2003 averaged $11.19 per Boe, which was also in-line with our average finding and development cost since inception of the Company of $11.57 per Boe. We believe that our finding and development costs

Proved Reserves
Mmboe as of 12/31



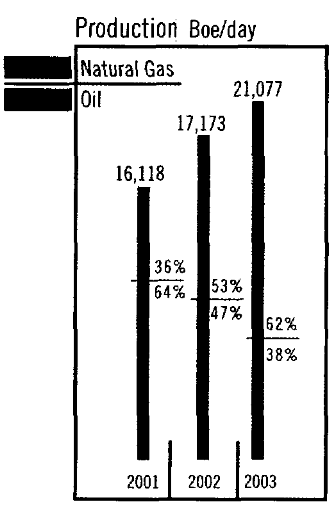
# CREATING VALUE



# STRATEGIC REVIEW

are very competitive with similar Gulf of Mexico producers, for whom finding and development costs have recently averaged in the range of $10 to $15 per Boe. While there were no purchases of reserves in 2003, reserve acquisitions have been an integral part of our growth strategy and, since inception, have replaced an average of 173% of annual production at an average cost of $6.10 per Boe.

Production volumes for 2003 increased 23% to 21,077 Boe per day from 17,173 Boe per day in 2002. All of the production increase was achieved through successful drilling with no benefit from acquisitions. During 2003, we operated approximately 89% of our production. Approximately 62% of production was natural gas and 38% was oil, compared with 53% natural gas and 47% oil in 2002.




During 2003, cash operating costs, comprised of lease operating expense, taxes other than on earnings and general and administrative expenses, fell 10% to $9.24 per Boe from $10.32 per Boe in 2002. In particular, lease operating expense fell significantly on a per-unit basis to $4.77 per Boe for 2003, from $5.49 in 2002 and $6.21 in 2001. Aggressive controls and cost reduction incentive programs together with increased operating scale were the key factors in the reduction in costs.

In 2003 we spent $111.9 million in our exploration and development program, up 64% from the $68.1 million invested in 2002. Approximately $60.2 million was spent on our expanded exploratory program, including the completion of our exploratory successes. An additional $45.7 million went to development drilling, facility and pipeline construction costs associated with the development of our drilling successes; and $6 million was for lease acquisitions and seismic. We were active in several federal and state lease sales and in those sales added approximately 32,600 gross acres to our inventory. As of December 31, 2003, we owned an interest in 315 producing wells and held an interest in 151,717 gross acres of developed properties and 83,098 gross acres of undeveloped properties.

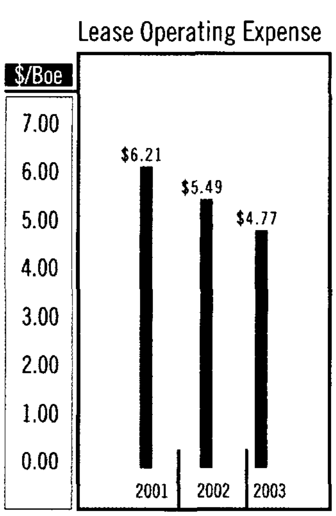
Our largest capital investment during 2003 was again at East Bay, our cornerstone producing property which also continues to present new exploratory opportunities. We invested a total of $25.3 million in the area, including two new successful exploratory wells and 20 workovers and recompletions, as well as seismic acquisition and reprocessing, and facility construction. The balance of our capital was allocated to a number of different projects, all in the shallow to moderate depth waters of the Gulf of Mexico Shelf.

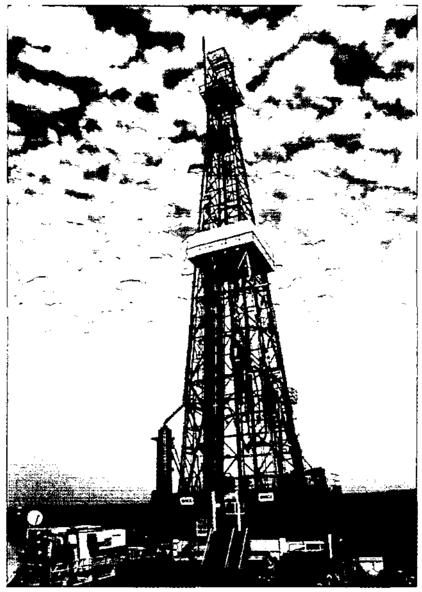
One of the best discoveries in our history was the 65%-owned Rock Creek discovery at South Timbalier 41, which we


CREATING VALUE

drilled in late 2003. South Timbalier 41 was acquired in the March 2003 Federal Lease Sale. This deep shelf well is on the block immediately to the south of South Timbalier 26, one of the first properties we owned, which is part of the Greater Bay Marchand complex. At least two follow-up wells are planned in 2004. The close proximity of the field to existing infrastructure on South Timbalier 26 will facilitate efficient development of our Rock Creek discovery.

Another significant discovery in 2003 was the Mesa Verde East prospect in East Bay. This well was a follow up to our success at the Mesa Verde prospect in 2002 and is an example of why we regard East Bay as one of the most important exploratory areas for us. We have also followed the productive horizons to the western side of the Mississippi River, where we have recently acquired additional acreage and identified a number of



prospects with the same geologic characteristics. We have several wells in this area planned for 2004.

In 2003, we also participated with industry partners at two meaningful multi-well discoveries at South Marsh Island 109 and High Island 55-L. We drilled three exploration wells on each of these blocks in 2003, and we expect that the discoveries on High Island 55-L will come on production in the second quarter. Platform construction is currently underway at South Marsh Island 109, and those three discoveries should be on production early in the second half of the year. We also plan to drill at least one more exploratory well on the block after the platform is in place.

For 2004, we are beginning the year with a capital budget of $125 million. Approximately 40% of the budget has been reserved for the exploration program, with 25% targeting moderate risk exploration and 15% targeting higher risk, higher potential projects. The remaining 60% of the capital budget will be reserved for low risk exploitation and development opportunities, including developing exploratory successes drilled in the latter part of last year. The risk profile of this year's program is very similar to that of the past two years, and we intend to fund the program entirely from internally generated funds. We expect to drill between 26 and 30 exploratory wells in 2004 as well as 8 to 12 development wells. Included in our plans are 3 to 5 wells in the Greater Bay Marchand area, which includes follow-up wells to our recent discoveries at South Timbalier 26 and 41. We plan to drill 5 to 7 exploratory wells at East Bay, which continues to be an exciting exploratory province for the Company. The remainder of our budget will be allocated to drilling projects elsewhere on the Gulf of Mexico Shelf and to our first onshore exploratory wells in the marshes of south Louisiana.

EPL 10-K

# CONTINUING MOMENTUM

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

# Form 10-K

(Mark One)

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

**For the fiscal year ended December 31, 2003**

**or**

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

**For the transition period from to**

**Commission file number: 001-16179**

# Energy Partners, Ltd.
*(Exact name of registrant as specified in its charter)*

| | |
|---|---|
| **Delaware**<br>*(State or other jurisdiction of incorporation or organization)* | **72-1409562**<br>*(I.R.S. Employer Identification No.)* |
| **201 St. Charles Avenue, Suite 3400**<br>**New Orleans, Louisiana**<br>*(Address of principal executive offices)* | **70170**<br>*(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 check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined by Rule 12b-2 of the Act). Yes ☑ No ☐

The aggregate market value of the common stock held by non-affiliates of the registrant at June 30, 2003 based on the closing price of such stock as quoted on the New York Stock Exchange on that date was $213,337,290.

As of February 25, 2004 there were 32,455,736 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 2004 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 "Additional Factors Affecting Business" in Items 1 and 2 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 are an independent oil and natural gas exploration and production company focused on the shallow to moderate depth waters of the Gulf of Mexico Shelf. We concentrate on the Gulf of Mexico Shelf region because that area 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 this region offers a balanced and expansive array of existing and prospective exploration, exploitation and development opportunities in both established productive horizons and deeper geologic formations. As of December 31, 2003, we had estimated proved reserves of approximately 134.4 Bcf of natural gas and 27.4 Mmbbls of oil, or an aggregate of approximately 49.8 Mmboe, with a present value of estimated pre-tax future net cash flows of $967.4 million, and a standardized measure of discounted future net cash flows of $529.4 million.

Since our incorporation in January 1998 by Richard A. Bachmann, our founder, chairman, president and chief executive officer, we have assembled 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 mature oil and natural gas fields in the Gulf of Mexico Shelf area, including the acquisition of Hall-Houston Oil Company ("HHOC") in early 2002. The acquisition of HHOC strengthened our management team, expanded our property base, reduced our geographic concentration, and moved us to a more balanced oil and natural gas reserves and production profile. This acquisition also expanded our technical knowledge base through the addition of high quality personnel and geophysical and geological data. Furthermore, the acquisition significantly improved our portfolio of exploration opportunities by adding 12 offshore exploratory blocks to complement our development and drill-to-earn portfolio.

On November 1, 2000, we consummated our initial public offering and began trading our common shares 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, by the time of our 2004 Annual Meeting of Stockholders, we will post our Corporate Governance Guidelines and the charters for our Audit, Compensation and Nominating Committees on our web site. 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.

*Exploration and Development Expenditures*

Our exploration and development expenditures for 2003 totaled $112.7 million inclusive of an $0.9 million contingent consideration payment to former HHOC stockholders resulting from the January 2002 acquisition of HHOC. For 2004, we have budgeted exploration and development expenditures of $125 million. This budget includes a mixture of lower risk development and exploitation wells, moderate risk exploration opportunities and higher risk, higher potential exploration projects and does not include acquisitions.

## Our Properties

At December 31, 2003, we had interests in 24 producing fields and 6 fields under development, all of which are located in the Gulf of Mexico Shelf region. These fields fall into three focus areas which we identify as our Eastern, Central and Western areas. The Eastern area is comprised of two fields, including the East Bay field. The Central area is comprised of six fields, four of which are contiguous and together cover most of the Bay Marchand salt dome. The Western area is comprised of 17 producing fields.

### Eastern Area

East Bay is the key asset in our Eastern 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 85 feet. East Bay encompasses nearly 48 square miles and is comprised primary of, South Pass 24, 26 and 27 fields. Through recent state and federal lease sales, we acquired acreage that is contiguous to East Bay in several additional South Pass and West Delta blocks. We are the operator of these fields and own an average 93% working interest with our working interest ranging from 50% to 100% and our net revenue interest ranging from 42% to 86%. Inclusive of all lease acquisitions, our lease area covers 42,103 gross acres (39,154 net acres).

Our Eastern area operations accounted for approximately 45% of our net daily production and 22% ($25.3 million) of our capital expenditures during 2003.

### Central Area

The focus of our Central area operations is Greater Bay Marchand, which is located approximately 60 miles south of New Orleans in water depths of 60 feet or less and encompasses nearly 100 square miles. Our key assets in Greater Bay Marchand include the Bay Marchand, South Timbalier 26 and South Timbalier 41 fields.

Through a series of acquisitions we obtained a 50% interest in the South Timbalier 26 field in early 2000. We continue to serve as operator of this field where we have interests in 13 producing wells. In 2003, the Company drilled a well in the South Timbalier 41 field, our Rock Creek discovery, that is currently under development. The field may be able to utilize existing infrastructure owned by us in the adjacent South Timbalier 26 field and is expected to be on production by mid 2004.

Our Central area operations accounted for approximately 16% of our net daily production and 21% ($23.7 million) of capital expenditures during 2003.

### Western Area

In connection with the HHOC acquisition in early 2002, we added ten producing fields and one field under development to our property portfolio in our Western area. The properties acquired in the acquisition are located in water depths ranging from 20 to 476 feet. We operate all of these properties, with working interests ranging from 17% to 100%. Subsequent to the acquisition, we acquired 5 leases at the March 2002 and 2003 federal lease sales and also acquired working interests in several additional leases through trades with industry partners, which brought our total number of fields in this area at December 31, 2003 to 17 producing fields with another five under development.

Our Western area operations accounted for approximately 39% of our net daily production and 57% ($63.7 million) of our capital expenditures during 2003.

**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, 2003, 2002 and 2001. The December 31, 2003 and 2002 estimates of proved reserves are based on reserve reports prepared by Netherland, Sewell & Associates, Inc. and Ryder Scott Company, L.P., independent petroleum engineers, and the December 31, 2001 estimates are based on a reserve report prepared by Netherland, Sewell & Associates, Inc. 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, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| Total estimated net proved reserves: | | | |
| Oil (Mbbls) | 27,414 | 26,353 | 25,462 |
| Natural gas (Mmcf) | 134,404 | 126,957 | 61,797 |
| Total (Mboe) | 49,815 | 47,513 | 35,762 |
| Net proved developed reserves(4): | | | |
| Oil (Mbbls) | 22,306 | 21,070 | 22,176 |
| Natural gas (Mmcf) | 71,531 | 70,014 | 38,099 |
| Total (Mboe) | 34,228 | 32,739 | 28,526 |
| Estimated future net revenues before income taxes (in thousands)(2) | $967,449 | $815,985 | $168,007 |
| Present value of estimated future net revenues before income taxes (in thousands)(1)(2) | $701,237 | $608,273 | $129,122 |
| Standardized measure of discounted future net cash flows (in thousands)(3) | $529,415 | $476,901 | $123,377 |

(1) 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.

(2) 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, while the December 31, 2002 amount was calculated using a period-end oil price of $29.53 per barrel and a period-end natural gas price of $4.83 per Mcf and the December 31, 2001 amount was calculated using a period-end oil price of $18.21 per barrel and a period-end price of $2.71 per Mcf.

(3) The standardized measure of discounted future net cash flows represents the present value of future cash flows after income tax discounted at 10%.

(4) Net proved developed non-producing reserves as of December 31, 2003 were 9,600 Mbbls and 41,294 Mmcf.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures. For a discussion of these uncertainties, see "Additional Factors Affecting Business."

### 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, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | | (In thousands) | |
| Business combinations: | | | |
| Proved properties | $ 850 | $116,415 | $ 523 |
| Unproved properties | — | 7,616 | — |
| Total business combinations | 850 | 124,031 | 523 |
| Lease acquisitions | 6,030 | 1,922 | 1,993 |
| Exploration | 60,170 | 27,083 | 45,592 |
| Development | 45,682 | 39,061 | 55,882 |
| Total finding and development costs | 111,882 | 68,066 | 103,467 |
| Total finding, development and acquisition costs | 112,732 | 192,097 | 103,990 |
| Asset retirement liabilities incurred | 812 | — | — |
| Asset retirement revisions | 2,519 | — | — |
| Costs incurred | $116,063 | $192,097 | $103,990 |

### 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, 2003:

| | Total Productive Wells | |
|---|---|---|
| | Gross | Net |
| Oil | 259 | 226 |
| Natural gas | 56 | 48 |
| Total | 315 | 274 |

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. Sixteen gross oil wells and five gross natural gas wells have dual completions.

## Acreage

The following table sets forth information as of December 31, 2003 relating to acreage held by us. Developed acreage is assigned to producing wells.

| | Gross Acreage | Net Acreage |
|---|---|---|
| Developed: | | |
| Eastern area | 32,079 | 29,659 |
| Central area | 25,091 | 8,897 |
| Western area | 94,547 | 61,065 |
| Total | 151,717 | 99,621 |
| Undeveloped: | | |
| Eastern area | 10,336 | 9,674 |
| Central area | 15,403 | 13,161 |
| Western area | 57,359 | 42,032 |
| Total | 83,098 | 64,867 |

Leases covering 5% of our undeveloped net acreage will expire in 2004, approximately 10% in 2005, 42% in 2006, 11% in 2007, and 32% in 2008.

## Well Activity

The following table shows our well activity for the years ended December 31, 2003, 2002 and 2001. 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, | | | | | |
|---|---|---|---|---|---|---|
| | 2003 | | 2002 | | 2001 | |
| | Gross | Net | Gross | Net | Gross | Net |
| Development Wells: | | | | | | |
| Productive | 1.0 | 0.3 | 1.0 | 1.0 | 2.0 | 1.0 |
| Non-productive | 1.0 | 1.0 | — | — | — | — |
| Total | 2.0 | 1.3 | 1.0 | 1.0 | 2.0 | 1.0 |
| Exploration Wells: | | | | | | |
| Productive | 15.0 | 8.4 | 9.0 | 5.1 | 15.0 | 9.6 |
| Non-productive | 4.0 | 2.2 | 3.0 | 0.9 | 5.0 | 4.0 |
| Total | 19.0 | 10.6 | 12.0 | 6.0 | 20.0 | 13.6 |

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, 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 uncontrolled 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.

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 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 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. 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 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.

***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 bonds and plugging and abandonment 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 Minerals Management Service ("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 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 Region VI National Production Discharge Elimination System Permit 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 the permit.

*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 Protected Areas.* Executive Order 13158, issued on May 26, 2000, directs federal agencies to safeguard existing Marine Protected Areas ("MPAs") in the United States and establish new MPAs. The order requires federal agencies to avoid harm to MPAs to the extent permitted by law and to the maximum extent practicable. It also directs the EPA to propose new regulations under the Clean Water Act to ensure appropriate levels of protection for the marine environment. This order has the potential to adversely affect our operations by restricting areas in which we may carry out future development and exploration projects and/or causing us to incur increased operating expenses.

*Marine Mammal and Endangered Species.* Federal Lease Stipulations address 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. Effective January 1, 2003, 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.

**Additional Factors Affecting Business**

***Exploration and Drilling Risks***

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; and
- limitations in the market for oil and natural gas.

***Liability Risks***

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.

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, but we are not fully insured against all risks. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. 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 us.

*Volatility of Oil and Natural Gas Prices*

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;
- weather 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 or ability to finance planned capital expenditures. Further, oil prices and natural gas prices do not necessarily move together.

*Uncertainty of Estimates of Oil and Natural Gas 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.

### *Marketability of 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.

### *A Significant Part of the Value of Our Production and Reserves is Concentrated in One Property*

During the month of December 2003, 36% of our net daily production came from our East Bay field. If mechanical problems, storms or other events curtail a substantial portion of this production, our cash flow would be affected adversely. Also, at December 31, 2003, approximately 48% of our proved reserves were located on this property. If the actual reserves associated with this property 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 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 on the Gulf of Mexico Shelf. Production from reserves in reservoirs in the Gulf of Mexico generally declines more rapidly than from reservoirs in many other producing regions of the world. As a result, our reserve replacement needs from new investments are relatively greater. 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.

*Acquisition of Additional Reserves*

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;
- 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.

*Capital Requirements*

In order to finance acquisitions of additional producing properties, finance the development of any discoveries made through any expanded exploratory program that might be undertaken or enter into significant drill-to-earn programs, 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, drill-to-earn programs 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 acquisitions, drill-to-earn programs or other transactions or to obtain additional external funding on terms acceptable to us.

*Availability and Costs of Resources*

All of our operations are on the Gulf of Mexico Shelf. Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our development and exploration operations, which could have a material adverse effect on our business, financial condition or results of operations. Periodically, drilling activity in the Gulf of Mexico has increased, and 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 also decreases the availability of offshore rigs. 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.

*Reliance on Key Personnel*

To a large extent, we depend on the services of our founder and chairman, president and chief executive officer, Richard A. Bachmann, and other senior management personnel. The loss of the services of Mr. Bachmann 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.

The Gulf of Mexico Shelf area is highly competitive, and our success there will depend largely on our ability to attract and retain experienced geoscientists and other professional staff.

*Competition*

We operate in a highly competitive environment for acquiring oil and natural gas properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in Gulf of Mexico activities. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. 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.

**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 policy and can be cancelled by either party. In the event that the contract is cancelled by us, Shell has the right to match any other offers we receive for purchase of our oil production. Our oil, condensate and natural gas production is sold to a variety of purchasers, typically at market-sensitive prices. Our purchasers of oil and condensate include ChevronTexaco and Shell. Currently, our 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. We also have a natural gas processing arrangement for our production at our Bay Marchand and East Bay fields with Dynegy Midstream Services, L.P. Of our total oil and natural gas revenues in 2003, Shell accounted for approximately 30 percent and Dreyfus 10 percent.

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, 2003, we had 142 full-time employees, including 46 geoscientists, engineers and technicians and 54 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 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 | 59 | Chairman, President and Chief Executive Officer |
| Gary L. Hall | 54 | Vice Chairman |
| Suzanne V. Baer | 56 | Executive Vice President and Chief Financial Officer |
| John H. Peper | 51 | Executive Vice President, General Counsel and Corporate Secretary |
| Bruce R. Sidner | 54 | Executive Vice President of Exploration |
| T. Rodney Dykes | 47 | Senior Vice President — Production |
| William Flores, Jr. | 46 | Senior Vice President — Drilling |

Richard A. Bachmann has been president and chief executive officer and chairman of the board of directors since our incorporation in January 1998. 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 is also a director of Superior Energy Services, Inc.

Gary L. Hall joined us in January 2002, following the closing of the HHOC acquisition, as vice chairman and a member of our board of directors. Prior to joining us, Mr. Hall had been chairman of the board of directors and chief executive officer of HHOC since it began operations in 1983. He has been involved in the oil and natural gas exploration and production business in the Gulf of Mexico since 1976, serving in various positions with major integrated and independent energy companies including Mobil Oil Company and Pogo Producing Company.

Suzanne V. Baer joined us in April 2000 as vice president and chief financial officer and was promoted to executive vice president in May 2001. Ms. Baer has 34 years of financial management, investor relations and treasury experience in the energy industry. From July 1998 until March 2000, Ms. Baer had been vice president and treasurer of Burlington Resources Inc. and, from October 1997 to July 1998, was vice president and assistant treasurer of Burlington Resources. Prior to the merger of LL&E with Burlington Resources in 1997, Ms. Baer was vice president and treasurer of LL&E since 1995.

John H. Peper joined us in January 2002, following the closing of the HHOC acquisition, 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 HHOC since February 1993. Mr. Peper also served as a director of HHOC since October 1991. 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.

Bruce R. Sidner joined us in January 2002, following the closing of the HHOC acquisition, as executive vice president of exploration. Prior to joining us, Mr. Sidner had been vice-president, exploration, of HHOC since February 1984. Mr. Sidner also served as a director of HHOC since 1990. For the seven years prior to joining HHOC, Mr. Sidner served in various positions with major integrated and independent energy companies including Exxon Production Research and Pogo Producing Company.

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.

William Flores, Jr. joined us in August 2003 as senior vice president — drilling. Mr. Flores has over 22 years experience in the energy industry. From 1999 to 2003, he was senior vice president of drilling for Ocean Energy, Inc. and from 1993 to 1999 he was vice president of operations of Ocean Energy, Inc. From 1988 to 1993, Mr. Flores was a senior drilling engineer for CNG Producing. From 1983 to 1988, he worked as a consulting engineer at the consulting firm of Stokes and Spiehler. Prior to 1983, Mr. Flores was a petroleum engineer for Apache Oil Company.

## 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 |
|---|---|---|
| 2002 | | |
| First Quarter | $ 8.63 | $ 5.90 |
| Second Quarter | 9.30 | 6.51 |
| Third Quarter | 9.00 | 6.40 |
| Fourth Quarter | 11.80 | 7.70 |
| 2003 | | |
| First Quarter | 11.60 | 9.26 |
| Second Quarter | 12.29 | 9.40 |
| Third Quarter | 11.85 | 10.00 |
| Fourth Quarter | 14.10 | 10.80 |
| 2004 | | |
| First Quarter (through February 25, 2004) | 14.81 | 12.81 |

On February 25, 2004, the last reported sale price of our common stock on the New York Stock Exchange was $13.29 per share.

As of February 25, 2004, there were approximately 129 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, | | | | |
|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2000 | 1999 |
| | (In thousands, except per share data) | | | | |
| Statement of Operations Data: | | | | | |
| Revenue | $ 230,187 | $133,788 | $ 146,240 | $ 111,017 | $ 9,509 |
| Income (loss) from operations(1) | 58,560 | (6,600) | 20,663 | (940) | (835) |
| Net income (loss)(2) | 33,250 | (8,799) | 11,974 | (18,684) | (2,284) |
| Net income (loss) available to common stockholders(3) | 29,705 | (12,129) | 11,974 | (25,387) | (3,120) |
| Basic net income (loss) per common share | $ 0.96 | $ (0.44) | $ 0.45 | $ (2.27) | $ (0.22) |
| Diluted net income (loss) per common share | $ 0.93 | $ (0.44) | $ 0.44 | $ (2.27) | $ (0.22) |
| Cash flows provided by (used in): | | | | | |
| Operating activities | $ 136,702 | $ 25,417 | $ 91,847 | $ 50,703 | $ (4,594) |
| Investing activities | (110,057) | (54,380) | (121,067) | (130,378) | (19,233) |
| Financing activities | 77,631 | 29,079 | 25,871 | 60,742 | 45,457 |

| | As of December 31, | | | | |
|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2000 | 1999 |
| | (In thousands) | | | | |
| Balance Sheet Data: | | | | | |
| Total assets | $544,181 | $384,220 | $242,777 | $208,149 | $69,276 |
| Long-term debt, excluding current maturities | 150,317 | 103,687 | 25,408 | 100 | 10,150 |
| Mandatorily redeemable preferred stock | — | — | — | — | 56,475 |
| Stockholders' equity | 261,485 | 191,922 | 164,867 | 150,591 | (3,815) |
| Cash dividends per common share | — | — | — | — | — |

(1) The 2000 loss from operations includes a one time non-cash stock compensation charge for shares released from escrow to management and director stockholders of $38.2 million and a non-cash charge of $2.1 million for bonus shares awarded to employees at the time of the initial public offering. The after-tax amount of these charges totaled $39.5 million. Although these charges reduced our net income, they increased paid-in-capital and thus did not result in a net reduction of total stockholders' equity. These charges were partially offset by a gain on sale of oil and natural gas assets of $7.8 million.

(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 $3.5 million and $3.3 million from net income (loss) for the years ended December 31, 2003 and 2002, respectively; and by subtracting preferred stock dividends and accretion of issuance costs of $6.7 million and $0.8 million for the years ended December 31, 2000 and 1999, 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 operations are concentrated in the shallow to moderate depth waters of the Gulf of Mexico Shelf.

In 2003, we reported another year of growth and progress with the best year on a per-share basis over our six-year history. Our strong cash flow provided us the flexibility to make necessary and appropriate investments to continue our long-term growth strategy. Our long-term strategy is 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. 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 in our core focus 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.

On January 15, 2002, we acquired HHOC for consideration of $88.3 million and the assumption of HHOC's working capital deficit. The consideration included the issuance of $38.4 million of 11% Senior Subordinated Notes due 2009 (the "Notes"). We also issued Series D Exchangeable Convertible Preferred Stock with a fair value at the issue date of $34.7 million ($38.4 million face amount) with an effective dividend rate of 10%. The acquisition moved our operations to a more balanced oil and natural gas reserves and production profile and reduced our production exposure to any particular field. Through the acquisition we added 59.1 Bcfe of proved reserves in January 2002, 98% of which were natural gas. The acquisition also included 10 producing properties and 12 offshore exploratory blocks. We have included the results of operations from the HHOC acquisition from the closing date of January 15, 2002. This acquisition has significantly affected our results of operations and production growth and will affect the comparability of our historical results of operations with results of operations from 2001.

On November 1, 2000, we consummated our initial public offering of 5.75 million shares of common stock. 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. 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 and to repay substantially all of the borrowings outstanding under our bank credit facility. The remainder of the net proceeds has been 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.

We amended our bank credit facility in connection with the Debt Offering. The amendment reduced the borrowing base under our bank credit facility to $60 million upon consummation of the Debt Offering. The borrowing base remains subject to redetermination based on the proved reserves of our oil and natural gas properties.

During 2003, Evercore, on two occasions exercised a contractual right to request us to register with the SEC the possible public sale of our common stock held by it. Subsequent to each of these requests Evercore priced two public offerings to sell shares of our common stock. These offerings completed the sale of its interest in our company. We did not sell any shares in either of these two offerings and did not receive any proceeds from the shares offered by Evercore.

Our revenue, profitability and future growth rate depend on a number of factors beyond our control, such as 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 "Additional Factors Affecting Business" in Items 1 and 2 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 in 2004, 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. We believe this year will provide us a number of opportunities to acquire targeted properties within our focus area.

## Results of Operations

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| Net production (per day): | | | |
| Oil (Bbls) | 7,978 | 8,148 | 10,358 |
| Natural gas (Mcf) | 78,596 | 54,150 | 34,562 |
| Total (Boe) | 21,077 | 17,173 | 16,118 |
| Oil & natural gas revenues (in thousands): | | | |
| Oil | $ 81,599 | $ 70,311 | $ 88,633 |
| Natural gas | 148,104 | 63,835 | 55,511 |
| Total | 229,703 | 134,146 | 144,144 |
| Average sales prices(1): | | | |
| Oil (per Bbl) | $ 28.02 | $ 23.64 | $ 23.44 |
| Natural gas (per Mcf) | 5.16 | 3.23 | 4.40 |
| Total (per Boe) | 29.86 | 21.40 | 24.50 |
| Average costs (per Boe): | | | |
| Lease operating expense | $ 4.77 | $ 5.49 | $ 6.21 |
| Taxes, other than on earnings | 0.99 | 1.05 | 1.22 |
| Depreciation, depletion and amortization | 10.65 | 10.29 | 7.97 |
| Increase (decrease) in oil and natural gas revenue (net of hedging) due to: | | | |
| Change in prices of oil | $ 13,027 | $ 757 | |
| Change in production volumes of oil | (1,739) | (19,079) | |
| Total increase in oil sales | 11,288 | (18,322) | |
| Change in prices of natural gas | $ 38,183 | $(14,743) | |
| Change in production volumes of natural gas | 46,086 | 23,067 | |
| Total increase in natural gas sales | 84,269 | 8,324 | |

| | As of December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| Total estimated net proved reserves: | | | |
| Oil (Mbbls) | 27,414 | 26,353 | 25,462 |
| Natural gas (Mmcf) | 134,404 | 126,957 | 61,797 |
| Total (Mboe) | 49,815 | 47,513 | 35,762 |
| Present value of estimated future net cash flows before income taxes (in thousands) | $701,237 | $608,273 | $129,122 |
| Standardized measure of discounted future net cash flows (in thousands) | $529,415 | $476,901 | $123,377 |

(1) Net of the effect of hedging transactions, which reduced oil price realizations by $1.67, $0.51 and $0.10 per Bbl, for 2003, 2002 and 2001, respectively and reduced gas price realizations by $0.23, $0.18 and $0.05 per Mcf for 2003, 2002 and 2001, respectively.

### *Revenues and Net Income*

Our oil and natural gas revenues increased to $229.7 million in 2003 from $134.1 million in 2002. The significant increase for this period is the result of increased natural gas and oil prices and increased natural gas production due primarily to new production from 21 wells drilled in 2002 and in the first half of 2003. These increases were partially offset by natural reservoir declines. In addition, 2002 volumes were negatively affected by tropical storm activity.

Our oil and natural gas revenues decreased to $134.1 million in 2002 from $144.1 million in 2001. Although production volumes increased 7% on a barrel of oil equivalent basis, the 27% decline in natural gas price realizations more than offset this benefit and resulted in lower revenues.

We recognized net income of $33.3 million in 2003 compared to net loss of $8.8 million in 2002. The increase in net income was primarily due to the increase in oil and natural gas revenues previously discussed and partially offset by higher operating costs, as discussed below. We recognized a net loss of $8.8 million in 2002 compared to net income of $12.0 million in 2001. The decrease in net income was primarily due to the decrease in oil and natural gas revenues previously discussed, combined with higher depletion, depreciation and amortization expense incurred primarily as a result of the HHOC acquisition. The following items had a significant impact on our net income or loss in 2003, 2002 and 2001 and affect the comparability of the results of operations for those years:

- In January 2003, we adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" ("Statement 143") and the effect of adoption on our results of operations and financial condition included a cumulative effect of adoption income of $2.3 million, net of deferred income taxes of $1.3 million.
- In March 2002, in connection with management's plan to reduce costs and effectively combine the operations of HHOC with ours, we executed a severance plan and recorded an expense of $1.2 million.
- In December 2001, we purchased a financially-settled put swaption (the "put swaption"), which provided us with a financially-settled natural gas swap at $2.95 per Mmbtu for 30,000 Mmbtu per day for the period from February 2002 through January 2003. The put swaption also provided us the option to cancel the swap on January 15, 2002. In the fourth quarter of 2001, we recognized an expense of $1.9 million, related to the change in time value of the option portion of the contract compared to $0.5 million expensed in January 2002 related to the remaining change in time value. This expense is classified as other revenue in the consolidated statements of operations in 2002 and 2001.
- We recorded business interruption income of $3.5 million in 2001 as a result of the rupture of a high-pressure natural gas transfer line at our East Bay field. The rupture occurred in November 2000 and the transfer line was restored to service in February 2001. This income is classified as other revenue in the consolidated statements of operations in 2001.

*Operating Expenses*

Operating expenses were impacted by the following:

- Lease operating expense increased $2.3 million to $36.7 million in 2003. This is a result of the addition of production from new fields, whereas the majority of our new production in the past was primarily from our large fields with existing infrastructure and low variable cost. Despite the increase in absolute costs, our operating costs per Boe have decreased due to the lower fixed costs required for these new fields.

  Lease operating expense decreased $2.1 million to $34.4 million in 2002. The decrease is attributable to the concerted effort to reduce operating costs, primarily at our East Bay field, which more than offset additional costs from the HHOC properties.

- Taxes, other than on earnings increased $1.1 million to $7.7 million in 2003. This increase was due to the increase in the production volumes and prices received for our oil and natural gas production on state leases, primarily at East Bay and Bay Marchand, which is subject to Louisiana severance taxes. These taxes are expected to fluctuate from period to period depending on our production volume from state leases and the commodity prices received.

  Taxes, other than on earnings decreased $0.6 million to $6.6 million in 2002. This reduction was due to the decrease in the production volumes and prices received for our oil production on state leases subject to Louisiana severance taxes.

- Exploration expenditures increased $6.7 million to $17.4 million in 2003. The expense in 2003 is primarily the result of an increase in dry hole charges to $10.1 million as a result of exploratory wells drilled during the year which were found to be not commercially productive, as well as property impairments of $2.8 million, partially offset by a slight decrease in seismic expenditures and delay rentals to $4.5 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. Although our dry hole costs were higher in 2003, we allocated more dollars to exploration in 2003 while maintaining a comparable success rate.

  Exploration expenditures decreased $4.4 million to $10.7 million in 2002. The expense in 2002 is primarily the result of an increase in seismic expenditures and delay rentals to $4.8 million and a decrease in dry hole charges to $5.9 million as a result of exploratory wells drilled during the year which were found to be not commercially productive.

- Depreciation, depletion and amortization increased $17.4 million to $81.9 million in 2003. 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. Some fields carry a higher depreciation burden than others, therefore, changes in the location of our production will directly impact this expense. This expense includes $5.2 million for the provision of abandonment liabilities for 2003 as compared to $6.8 million in 2002.

  Depreciation, depletion and amortization increased $17.6 million to $64.5 million in 2002. The increase was due to the increased depreciable asset base resulting from the acquisition of HHOC and drilling activities subsequent to December 31, 2001, increased production volumes, amortization of unproved leases awarded at the March 2002 lease sale and acquired with HHOC and downward reserve revisions due to prices at December 31, 2001. This expense includes $6.8 million for the provision of abandonment liabilities as compared to $8.1 million in 2001.

- Other general and administrative expenses increased $4.2 million to $26.7 million in 2003. The increase was primarily due to increased compensation ($5.6 million) and increased insurance ($0.6 million) offset by a 2002 litigation settlement ($2.0 million), which increased general and administrative expenses during the prior year.

  Other general and administrative expenses increased $4.3 million to $22.5 million in 2002. The increase was primarily due to a litigation settlement ($2.0 million), increased insurance costs ($0.9 million), increased rent and other office costs ($1.0 million) and other costs associated with the combination of HHOC's operations with ours primarily in the first quarter of 2002 as we assimilated HHOC.

- Non-cash stock-based compensation expense of $1.3 million was recognized in 2003, an increase of $0.8 million from 2002. This expense has increased due to additional grants of restricted stock and the granting of performance share awards to employees.

  Non-cash stock-based compensation expense of $0.5 million was recognized in 2002, a decrease of $1.2 million from 2001. This expense relates to restricted stock and stock option grants made to employees.

### *Other Income and Expense*

Interest expense increased $3.2 million to $10.2 million in 2003. The increase was a result of interest expense on the 8.75% Senior Notes issued in August 2003 partially offset by the interest savings from the redemption of the 11% Notes and the repayment of the bank facility.

Interest expense increased $5.1 million to $7.0 million in 2002. The increase was a result of increased borrowings under our bank facility and the issuance of the Notes on January 15, 2002 related to the acquisition of HHOC.

**Financial Condition, Liquidity and Capital Resources**

The increase in revenues we experienced in 2003 significantly increased our cash flows from operations, which totaled $136.7 million in 2003. We intend to fund our exploration and development expenditures from internally generated cash flow, which we define as cash flow from operations before consideration of changes in working capital plus total exploration expenditures. Our cash on hand at December 31, 2003 was $104.4 million. Our future internally generated cash flows will depend on our ability to maintain and increase production through our development and exploratory 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 July 28, 2003, consists of a revolving line of credit with a group of banks available through March 30, 2005 (the "bank facility"). The bank facility currently has a borrowing base of $60 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 facility as set out in the reserve report delivered to the banks each April 1 and October 1. The bank facility permits both prime rate based 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 facility. The spread can range from 1.50% to 2.25% above LIBOR and 0% to 0.75% above prime. The borrowing base under the bank facility is secured by substantially all of our assets. At March 1, 2004, we had $0.1 million outstanding and $59.9 million of credit capacity available under the bank 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 of 1.1, (ii) maintain a minimum EBITDAX to interest ratio of 5.00 times, and (iii) maintain a minimum tangible net worth as calculated in accordance with the agreement. We were in compliance with these covenants at December 31, 2003.

On August 5, 2003, we issued, $150 million of 8.75% Senior Notes due 2010. The 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 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 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 Senior Notes are not subject to any sinking fund requirements.

Upon closing on the Senior Notes on August 5, 2003, we called our $38.4 million 11% Notes due 2009 for redemption. The redemption of the Notes in aggregate principal and accrued interest were funded with a portion of the proceeds received from the Senior Notes and was completed in August 2003. The Notes were issued on January 15, 2002 as part of the acquisition of HHOC. 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 $110.1 million used in investing activities in 2003 primarily included oil and natural gas property capital and exploration expenditures of $103.1 million and lease acquisitions of $6.0 million. Exploration expenditures incurred are excluded from operating cash flows and included in investing activities. During 2003, we completed 23 drilling projects and 33 recompletion/workover projects, 46 of which were successful. During 2002, we completed 17 drilling projects and 27 recompletion/workover projects, 34 of which were successful.

Our 2004 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 currently intend to allocate approximately 60% of our budget on an annual basis on low risk development and exploitation activities, approximately 25% to moderate risk exploration opportunities and approximately 15% to higher risk, higher potential exploration opportunities. Our exploration and development budget for 2004 is currently $125 million. 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 2004 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 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.

### 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, 2003:

| | Payments Due by Period | | | | |
|---|---|---|---|---|---|
| | Total | Less than 1 Year | 1-3 Years | 3-5 Years | Thereafter |
| | | | (In thousands) | | |
| Long-term debt | $150,416 | $ 99 | $ 317 | $ — | $150,000 |
| Operating leases | 15,135 | 2,445 | 5,280 | 3,931 | 3,479 |
| Unconditional purchase obligations(1) | 5,051 | 1,500 | 3,551 | — | — |
| Total contractual obligations | $170,602 | $4,044 | $9,148 | $3,931 | $153,479 |

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

### 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, zero-cost collars and a combination of options used 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 contract 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 the following contracts as of December 31, 2003:

**Natural Gas Positions**

| Remaining Contract Term | Contract Type | Strike Price ($/Mmbtu) | Volume (Mmbtu) Daily | Volume (Mmbtu) Total |
|---|---|---|---|---|
| 01/04 | Collar | $3.50/$5.40 | 10,000 | 310,000 |
| 01/04 | Collar | $3.50/$5.25 | 10,000 | 310,000 |
| 01/04 - 06/04 | Collar | $4.00/$7.00 | 10,000 | 1,820,000 |
| 01/04 - 12/04 | Collar | $4.00/$6.50 | 10,000 | 3,660,000 |
| 02/04 - 12/04 | Collar | $3.50/$8.00 | 10,000 | 3,350,000 |

**Crude Oil Positions**

| Remaining Contract Term | Contract Type | Strike Price ($/Bbl) | Volume (Bbls) Daily | Volume (Bbls) Total |
|---|---|---|---|---|
| 01/04 - 12/04 | Swap | $27.35 | 1,500 | 549,000 |
| 01/04 - 06/04 | Collar | $25.00/$31.38 | 1,500 | 273,000 |
| 07/04 - 09/04 | Collar | $24.00/$29.00 | 1,500 | 138,000 |
| 10/04 - 12/04 | Collar | $24.00/$28.75 | 1,500 | 138,000 |

On January 1, 2001, we adopted Statement of Financial Accounting Standards No. 133 ("Statement 133"), as amended, Accounting for Derivative Instruments and Hedging Activities. Statement 133 establishes accounting and reporting standards requiring 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 is effective, will be recognized in other comprehensive income (a component of stockholders' equity) until settled, when the resulting gains and losses will be recorded in earnings. Hedge ineffectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness, as defined by Statement 133, is charged currently to earnings.

Our hedged volume as of December 31, 2003 approximated 35% 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 statement 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 57 exploration wells, of which 13 were considered dry holes. Our dry hole costs charged to expense during this period totaled $29.5 million out of total exploratory drilling costs of $132.8 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 level and success of our exploratory program.

- *Proved Reserve Estimates* — Our independent reserve engineers prepare our oil and natural gas reserve estimates using guidelines established by the U.S. Securities and Exchange Commission and 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 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. 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 prices and costs 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, 2003 was based on period-end prices of $6.15 per Mcf for natural gas and $30.88 per barrel for crude oil 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. While we believe that future costs can be reasonably estimated, future prices are difficult to estimate since the market prices are influenced by events beyond our control. Future global economic and political events will most likely result in significant fluctuations in future oil prices. In addition, weather conditions can cause significant fluctuations in natural gas prices.

- *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. Material downward revisions in reserves increase the DD&A per unit and reduce our net income; likewise, material upward revisions lower the DD&A per unit and increase our net income.

- *Impairment of Oil and 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 could exceed its fair value. 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 reserves, or other changes to contracts, environmental regulations or tax laws. We cannot predict the need for, nor estimate the amount of, impairment charges that may be recorded in the future.

  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.

  In 2002, we adopted Statement 144 "Accounting for the Impairment or Disposal of Long-Lived Assets," ("Statement 144") which superseded Statement 121 "Accounting for Impairment of Long-Lived Assets." The Statement addresses financial accounting and reporting for the impairment or disposal of long-lived assets. The adoption of this statement did not have a material effect on our balance sheet or income statement in 2002.

  We estimate the amount of capitalized costs of unproved properties which will prove unproductive by amortizing the balance of the unproved property costs (adjusted by an anticipated rate of future successful development) over an average lease term. We will transfer the original cost of an unproved property to proved properties when we find commercial oil and natural gas reserves sufficient to justify full development of the property.

- *Asset retirement obligation* — We adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" ("Statement 143") on January 1, 2003. We have significant obligations to plug and abandon oil and natural gas wells and related equipment as well as to dismantle and abandon facilities at the end of oil and natural gas production operations. We record the fair value of a liability for an Asset Retirement Obligation ("ARO") in the period in which it is incurred and a corresponding increase in the carrying amount of the related asset. Subsequently, the ARO included in the carrying amount of the related asset are allocated to expense using the units-of-production method. In addition, accretion of the discount related to the ARO liability resulting from the passage of time is reflected as additional depreciation, depletion and amortization expense in the Consolidated Statement of Operations.

  Inherent in the fair value calculation of the ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment will be required to be made to the oil and natural gas property balance. This adjustment may then have a positive or negative impact on the associated depreciation expense and accretion expense depending on the nature of the revision.

- *Derivative instruments and hedging activities* — We enter into hedging transactions for our oil and natural gas production to reduce our exposure to fluctuations in the price of oil and natural gas. Our hedging transactions have to date consisted primarily of financially-settled swaps and zero-cost collars and combination options with major financial institutions. 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. Under the provisions of Statement 133, we are required to record our derivative instruments at fair market value as either assets or liabilities in our consolidated balance sheet. The fair value recorded is an estimate based on future commodity prices available at the time of the calculation. The fair market value could differ from actual settlements if 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.

Under the above critical accounting policies our net income can vary significantly from period to period because events or circumstances which trigger recognition as an expense for unsuccessful wells or impaired properties cannot be accurately forecast. In addition, selling prices for our oil and natural gas fluctuate significantly. Therefore we focus more on cash flow from operations and on controlling our finding and development, operating, administration, and financing costs.

**New Accounting Policies**

In November 2002, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" ("FIN 45"). FIN 45 requires a company to recognize a liability for the obligations it has undertaken in issuing a guarantee. This liability would be recorded at the inception of a guarantee and would be measured at fair value. The measurement provisions of this statement apply prospectively to guarantees issued or modified after December 31, 2002. The disclosure provisions apply to financial statements for periods ending after December 15, 2002. We do not currently have guarantees that require disclosure. We have adopted FIN 45, which did not have an impact on our financial position, results of operations or cash flows.

In December 2003, the FASB issued FASB Interpretation 46 (Revised December 2003), "Consolidation of Variable Interest Entities," ("FIN 46R") which addresses how a business enterprise should evaluate whether it has a controlling financial interest in an entity through means other than voting rights and accordingly should consolidate the entity. FIN 46R replaces FASB Interpretation 46, "Consolidation of Variable Interest Entities," which was issued in January 2003. We will be required to apply FIN 46R to variable interests in variable interest entities ("VIEs") no later than March 31, 2004. We have assessed the impact of FIN 46R, which will not currently have an impact on our financial position, results of operations or cash flows.

During the second quarter of 2002, the FASB issued Statement 145, Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections ("Statement 145"). This statement rescinds SFAS No. 4, Reporting Gains and Losses from Extinguishments of Debt, and requires that all gains and losses from extinguishments of debt should be classified as extraordinary items only if they meet the criteria of in APB No. 30. Applying APB No. 30 will distinguish transactions that are part of an entity's recurring operations from those that are unusual or infrequent or that meet the criteria for classification as an extraordinary item. Any gain or loss on extinguishment of debt that was classified as an extraordinary item in prior periods presented that does not meet the criteria in APB No. 30 for classification as an extraordinary item must be reclassified. We have adopted Statement 145, which did not have an impact on our financial position, results of operations or cash flows.

In June 2002, the FASB issued Statement 146, Accounting for Costs Associated with Exit or Disposal Activities ("Statement 146"). Statement 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and requires that liabilities associated with these costs be recorded at their fair value in the period in which the liability is incurred. Statement 146 became effective for disposal activities initiated after December 31, 2002. We have adopted Statement 146 which did not have an impact on our financial positions results of operations or cash flows.

In December 2002, the FASB issued Statement 148, "Accounting for Stock-Based Compensation — Transition and Disclosure" ("Statement 148"). Statement 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, Statement 148 amends the disclosure requirements of FASB Statement 123, "Accounting for Stock-Based Compensation," to require more prominent and frequent disclosures in financial statements about the effects of stock-based compensation. The transition guidance and annual disclosure provisions of Statement 148 are effective for fiscal years ending after December 15, 2002, while the interim disclosure provisions are effective for periods beginning after December 15, 2002. Disclosures required by this standard are included in the notes to these consolidated financial statements.

On April 30, 2003, the FASB issued Statement of Financial Accounting Standards No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" ("Statement 149"). Statement 149 amends and clarifies the accounting guidance on (1) derivative instruments (including certain derivative instruments embedded in other contracts) and (2) hedging activities that fall within the scope of FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("Statement 133"). Statement 149 also amends certain other existing pronouncements, which will result in more consistent reporting of contracts that are derivatives in their entirety or that contain embedded derivatives that warrant separate accounting. Statement 149 is effective (1) for contracts entered into or modified after June 30, 2003, with certain exceptions, and (2) for hedging relationships designated after June 30, 2003. The guidance is to be applied prospectively. We have adopted Statement 149, which did not have an impact on our financial position, results of operations or cash flows.

In May 2003, the FASB issued Statement of Financial Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity" ("Statement 150"). Statement 150 establishes standards for how an issuer classifies and measures in its statement of financial position certain financial instruments with characteristics of both liabilities and equity. In accordance with the standard, financial instruments that embody obligations for the issuer are required to be classified as liabilities. Statement 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise shall be effective at the beginning of the first interim period beginning after June 15, 2003. We have adopted the Statement 150, which did not have an impact on our financial position, the results of operations or cash flows.

Statement of Financial Accounting Standards No. 141, "Business Combinations," ("Statement 141") and No. 142, "Goodwill and Intangible Assets," ("Statement 142") became effective for us on July 1, 2001 and January 1, 2002, respectively. Statement 141 requires all business combinations initiated after June 30, 2001, to be accounted for using the purchase method. Additionally, Statement 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. Statement 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under Statement 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. The appropriate application of Statement 141 and 142 to oil and natural gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves is unclear. Depending on how the accounting and disclosure literature is clarified, these oil and natural gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds may be classified separately from oil and natural gas properties, as intangible assets on our balance sheets. Additional disclosures required by Statements 141 and 142 would be included in the notes to financial statements. Historically, we, like many other oil and natural gas companies, have included these oil and natural gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves as part of the oil and natural gas properties, even after Statements 141 and 142 became effective.

This interpretation of Statements 141 and 142 would affect only our balance sheet classification of oil and natural gas leaseholds. Our results of operations and cash flows would not be affected, since these oil and natural gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves would continue to be amortized in accordance with accounting rules for oil and natural gas companies provided in Statement of Financial Accounting Standards No. 19 "Financial Accounting and Reporting by Oil and Gas Producing Companies."

At December 31, 2003, we had unproved and proved leasehold of approximately $5.0 million and $100.0 million that would have been classified on the balance sheet as unproved intangible oil and natural gas properties and intangible acquired proved leaseholds, respectively, if we applied the interpretation currently being deliberated by the Emerging Issues Task Force ("EITF"). We will continue to classify our oil and natural gas leaseholds as oil and natural gas properties until further guidance is provided.

## Item 7A. *Quantitative and Qualitative Disclosures about Market Risk*

### Interest Rate Risk

We are exposed to changes in interest rates. Changes in interest rates affect the interest earned on our cash and cash equivalents and the interest rate paid on borrowings under our bank facility. Currently, we do not use interest rate derivative instruments to manage exposure to interest rate changes. At December 31, 2003, $0.1 million of our long-term debt had variable interest rates, while the remaining long-term debt had fixed interest rates, therefore an increase in the variable interest rate would not have a material impact on net income.

### Commodity Price Risk

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and natural gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under the bank facility is subject to periodic redetermination based in part on changing expectations of future prices. Lower prices may also reduce the amount of oil and natural gas that we can economically produce. We currently sell all of our oil and natural gas production under price sensitive or market price contracts.

We use derivative commodity instruments to manage commodity price risks associated with future oil and natural gas production. As of December 31, 2003, we had the following contracts in place:

**Natural Gas Positions**

| Remaining Contract Term | Contract Type | Strike Price ($/Mmbtu) | Volume (Mmbtu) Daily | Volume (Mmbtu) Total |
|---|---|---|---|---|
| 01/04 | Collar | $3.50/$5.40 | 10,000 | 310,000 |
| 01/04 | Collar | $3.50/$5.25 | 10,000 | 310,000 |
| 01/04 - 06/04 | Collar | $4.00/$7.00 | 10,000 | 1,820,000 |
| 01/04 - 12/04 | Collar | $4.00/$6.50 | 10,000 | 3,660,000 |
| 02/04 - 12/04 | Collar | $3.50/$8.00 | 10,000 | 3,350,000 |

**Crude Oil Positions**

| Remaining Contract Term | Contract Type | Strike Price ($/Bbl) | Volume (Bbls) Daily | Volume (Bbls) Total |
|---|---|---|---|---|
| 01/04 - 12/04 | Swap | $27.35 | 1,500 | 549,000 |
| 01/04 - 06/04 | Collar | $25.00/$31.38 | 1,500 | 273,000 |
| 07/04 - 09/04 | Collar | $24.00/$29.00 | 1,500 | 138,000 |
| 10/04 - 12/04 | Collar | $24.00/$28.75 | 1,500 | 138,000 |

Our hedged volume as of December 31, 2003 approximated 35% of our estimated production from proved reserves through the balance of the terms of the contracts. Had these contracts been terminated at December 31, 2003, we estimate the loss would have been $3.8 million.

We use a sensitivity analysis technique to evaluate the hypothetical effect that changes in the market value of crude oil and natural gas may have on fair value of our derivative instruments. At December 31, 2003, the potential change in the fair value of commodity derivative instruments assuming a 10% increase in the underlying commodity price was a $4.1 million increase in the combined estimated loss.

For purposes of calculating the hypothetical change in fair value, the relevant variables are the type of commodity (crude oil or natural gas), the commodities futures prices and volatility of commodity prices. The hypothetical fair value is calculated by multiplying the difference between the hypothetical price and the contractual price by the contractual volumes.

## GLOSSARY OF OIL AND NATURAL GAS TERMS

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

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

"Bcf" One billion cubic feet.

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

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

"Mbbls" One thousand barrels of oil or other liquid hydrocarbons.

"Mboe" One thousand barrels of oil equivalent.

"Mcf" One thousand cubic feet of natural gas.

"Mmbbls" One million barrels of oil or other liquid hydrocarbons

"Mmboe" One million barrels of oil equivalent

"Mmbtu" One million British Thermal Units.

"Mmcf" One million cubic feet of natural gas.

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

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

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

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

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

## REPORT OF MANAGEMENT

The consolidated financial statements of Energy Partners, Ltd. and subsidiaries and the related information included in this Report have been prepared by management in conformity with accounting principles generally accepted in the United States of America. The financial statements include amounts that are management's best estimates and judgments.

Management maintains a system of internal controls including internal accounting controls that provide management with reasonable assurance that our assets are protected and that published financial statements are reliable and free of material misstatement. Management is responsible for the effectiveness of internal controls. This is accomplished through established codes of conduct, accounting and other control systems, policies and procedures, employee selection and training, appropriate delegation of authority and segregation of responsibilities.

The Audit Committee of the Board of Directors, composed solely of directors who are not officers or employees of the Company, meets regularly with the independent certified public accountants, financial management and counsel. To ensure complete independence, the certified public accountants have full and free access to the Audit Committee to discuss the results of their audits, the adequacy of internal controls and the quality of financial reporting.

Our independent certified public accountants provide an objective independent review by their audit of the Company's financial statements. Their audit is conducted in accordance with auditing standards generally accepted in the United States of America and includes a review of internal accounting controls to the extent deemed necessary for the purposes of their audit.

| | |
|---|---|
| Richard A. Bachmann | Suzanne V. Baer |
| *Chairman, President and* | *Executive Vice President* |
| *Chief Executive Officer* | *and Chief Financial Officer* |

## INDEPENDENT AUDITORS' REPORT

The Board of Directors and Stockholders
Energy Partners, Ltd.:

We have audited the accompanying consolidated balance sheets of Energy Partners, Ltd. and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Energy Partners, Ltd. and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in note 2 to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations in 2003.

KPMG LLP

New Orleans, Louisiana
February 9, 2004

## ENERGY PARTNERS, LTD. AND SUBSIDIARIES

### CONSOLIDATED BALANCE SHEETS
**December 31, 2003 and 2002**
**(In thousands, except share data)**

| | 2003 | 2002 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 104,392 | $ 116 |
| Trade accounts receivable — net of allowance for doubtful accounts of $26 in 2003 and $1,351 in 2002 | 35,315 | 25,824 |
| Deferred tax assets | 2,939 | 1,221 |
| Prepaid expenses | 2,106 | 1,868 |
| Total current assets | 144,752 | 29,029 |
| Property and equipment, at cost under the successful efforts method of accounting for oil and gas properties | 598,101 | 471,840 |
| Less accumulated depreciation, depletion and amortization | (210,013) | (121,034) |
| Net property and equipment | 388,088 | 350,806 |
| Other assets | 6,575 | 3,463 |
| Deferred financing costs — net of accumulated amortization of $3,267 in 2003 and $2,365 in 2002 | 4,766 | 922 |
| | $ 544,181 | $ 384,220 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| Current liabilities: | | |
| Accounts payable | $ 14,650 | $ 8,869 |
| Accrued expenses | 42,487 | 43,533 |
| Fair value of commodity derivative instruments | 3,814 | 3,392 |
| Current maturities of long-term debt | 99 | 92 |
| Total current liabilities | 61,050 | 55,886 |
| Long-term debt | 150,317 | 103,687 |
| Deferred tax liabilities | 29,584 | 9,033 |
| Asset retirement obligation | 40,577 | 22,669 |
| Other | 1,168 | 1,023 |
| | 282,696 | 192,298 |
| Stockholders' equity: | | |
| Preferred stock, $1 par value per share. Authorized 1,700,000 shares; issued and outstanding: 2003 — 368,076 shares; 2002 — 382,261 shares. Aggregate liquidation value: 2003 — $36,808; 2002 — $38,226 | 34,894 | 35,359 |
| Common stock, par value $0.01 per share. Authorized 50,000,000 shares; issued and outstanding: 2003 — 32,241,981 shares; 2002 — 27,550,466 shares | 323 | 276 |
| Additional paid-in capital | 228,511 | 187,965 |
| Accumulated other comprehensive loss — net of deferred taxes of $1,373 in 2003 and $1,221 in 2002 | (2,441) | (2,171) |
| Retained earnings (deficit) | 198 | (29,507) |
| Total stockholders' equity | 261,485 | 191,922 |
| Commitments and contingencies | | |
| | $ 544,181 | $ 384,220 |

See accompanying notes to consolidated financial statements.

## ENERGY PARTNERS, LTD. AND SUBSIDIARIES

## CONSOLIDATED STATEMENTS OF OPERATIONS

**Years Ended December 31, 2003, 2002 and 2001**

**(In thousands, except per share data)**

| | 2003 | 2002 | 2001 |
|---|---|---|---|
| Revenue: | | | |
| Oil and natural gas | $229,703 | $134,146 | $144,144 |
| Other | 484 | (358) | 2,096 |
| | 230,187 | 133,788 | 146,240 |
| Costs and expenses: | | | |
| Lease operating | 36,693 | 34,400 | 36,543 |
| Taxes, other than on earnings | 7,650 | 6,572 | 7,190 |
| Exploration expenditures and dry hole costs | 17,353 | 10,735 | 15,141 |
| Depreciation, depletion and amortization | 81,927 | 64,513 | 46,870 |
| General and administrative: | | | |
| Stock-based compensation | 1,285 | 453 | 1,651 |
| Severance costs | — | 1,211 | — |
| Other general and administrative | 26,719 | 22,504 | 18,182 |
| Total costs and expenses | 171,627 | 140,388 | 125,577 |
| Income (loss) from operations | 58,560 | (6,600) | 20,663 |
| Other income (expense): | | | |
| Interest income | 380 | 107 | 329 |
| Interest expense | (10,174) | (6,988) | (1,916) |
| | (9,794) | (6,881) | (1,587) |
| Income (loss) before income taxes and cumulative effect of change in accounting principle | 48,766 | (13,481) | 19,076 |
| Income taxes | (17,784) | 4,682 | (7,102) |
| Net income (loss) before cumulative effect of change in accounting principle | 30,982 | (8,799) | 11,974 |
| Cumulative effect of change in accounting principle, net of income taxes of $1,276 | 2,268 | — | — |
| Net income (loss) | 33,250 | (8,799) | 11,974 |
| Less dividends earned on preferred stock and accretion of discount | (3,545) | (3,330) | — |
| Net income (loss) available to common stockholders | $ 29,705 | $(12,129) | $ 11,974 |
| Earnings per share: | | | |
| Basic: | | | |
| Before cumulative effect of change in accounting principle | $ 0.89 | $ (0.44) | $ 0.45 |
| Cumulative effect of change in accounting principle | 0.07 | — | — |
| Basic earnings (loss) per share | $ 0.96 | $ (0.44) | $ 0.45 |
| Diluted: | | | |
| Before cumulative effect of change in accounting principle | $ 0.87 | $ (0.44) | $ 0.44 |
| Cumulative effect of change in accounting principle | 0.06 | — | — |
| Diluted earnings (loss) per share | $ 0.93 | $ (0.44) | $ 0.44 |
| Weighted average common shares used in computing income (loss) per share: | | | |
| Basic | 30,822 | 27,467 | 26,865 |
| Incremental common shares | 4,753 | — | 55 |
| Diluted | 35,575 | 27,467 | 26,920 |

See accompanying notes to consolidated financial statements.

## ENERGY PARTNERS, LTD. AND SUBSIDIARIES

## CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

### Years Ended December 31, 2003, 2002 and 2001

### (In thousands)

| | Preferred Stock Shares | Preferred Stock | Common Stock Shares | Common Stock | Additional Paid-In Capital | Accumulated Other Comprehensive Income | Retained Earnings (Deficit) | Total |
|---|---|---|---|---|---|---|---|---|
| Balance at December 31, 2000 | — | $ — | 26,400 | $ 264 | $179,679 | $ — | $(29,352) | $150,591 |
| Stock-based compensation | — | — | — | — | 1,651 | — | — | 1,651 |
| Exercise of warrants | — | — | 466 | 5 | — | — | — | 5 |
| Common stock issued | — | — | 5 | — | — | — | — | — |
| Comprehensive income: | | | | | | | | |
| Net income | — | — | — | — | — | — | 11,974 | 11,974 |
| Fair value of commodity derivative instruments | — | — | — | — | — | 981 | — | 981 |
| Comprehensive income | | | | | | | | 12,955 |
| Other | — | — | — | — | (335) | — | — | (335) |
| Balance at December 31, 2001 | — | — | 26,871 | 269 | 180,995 | 981 | (17,378) | 164,867 |
| Effect of Hall-Houston acquisition | 384 | 34,746 | 575 | 6 | 6,235 | — | — | 40,987 |
| Stock-based compensation | — | — | 93 | 1 | 618 | — | — | 619 |
| Shares cancelled | — | — | (23) | — | (167) | — | — | (167) |
| Conversion of preferred stock | (2) | (145) | 17 | — | 145 | — | — | — |
| Common stock issued to 401(k) plan | — | — | 9 | — | 84 | — | — | 84 |
| Dividends on preferred stock | — | — | — | — | — | — | (2,572) | (2,572) |
| Accretion of discount on preferred stock | — | 758 | — | — | — | — | (758) | — |
| Comprehensive loss: | | | | | | | | |
| Net loss | — | — | — | — | — | — | (8,799) | (8,799) |
| Fair value of commodity derivative instruments | — | — | — | — | — | (3,152) | — | (3,152) |
| Comprehensive loss | | | | | | | | (11,951) |
| Other | — | — | 8 | — | 55 | — | — | 55 |
| Balance at December 31, 2002 | 382 | 35,359 | 27,550 | 276 | 187,965 | (2,171) | (29,507) | 191,922 |
| Stock-based compensation | — | — | 131 | 1 | 783 | — | — | 784 |
| Shares cancelled | — | — | (105) | (1) | (1,715) | — | — | (1,716) |
| Proceeds from equity offering, net of costs | — | — | 4,211 | 42 | 37,535 | — | — | 37,577 |
| Exercise of common stock options | — | — | 167 | 2 | 2,148 | — | — | 2,150 |
| Exercise of warrants into common stock | — | — | 30 | — | 102 | — | — | 102 |
| Conversion of preferred stock | (14) | (1,418) | 232 | 3 | 1,415 | — | — | — |
| Common stock issued to 401(k) plan | — | — | 16 | — | 174 | — | — | 174 |
| Dividends on preferred stock | — | — | — | — | — | — | (2,592) | (2,592) |
| Accretion of discount on preferred stock | — | 953 | — | — | — | — | (953) | — |
| Comprehensive income: | | | | | | | | |
| Net income | — | — | — | — | — | — | 33,250 | 33,250 |
| Fair value of commodity derivative instruments | — | — | — | — | — | (270) | — | (270) |
| Comprehensive income | | | | | | | | 32,980 |
| Other | — | — | 10 | — | 104 | — | — | 104 |
| Balance at December 31, 2003 | 368 | $34,894 | 32,242 | $ 323 | $228,511 | $(2,441) | $ 198 | $261,485 |

See accompanying notes to consolidated financial statements.

## ENERGY PARTNERS, LTD. AND SUBSIDIARIES

## CONSOLIDATED STATEMENTS OF CASH FLOWS
**Years Ended December 31, 2003, 2002 and 2001**
**(In thousands)**

| | 2003 | 2002 | 2001 |
|---|---|---|---|
| Cash flows from operating activities: | | | |
| Net income (loss) | $ 33,250 | $(8,799) | $ 11,974 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | | |
| Cumulative effect of change in accounting principle, net of tax | (2,268) | — | — |
| Depreciation, depletion and amortization | 81,927 | 64,513 | 46,870 |
| (Gain) loss on sale of oil and gas assets | (207) | 243 | (39) |
| Amortization of deferred revenue | — | (3,420) | — |
| Stock-based compensation | 1,285 | 453 | 1,651 |
| Deferred income taxes | 17,708 | (4,653) | 7,023 |
| Exploration expenditures | 12,810 | 5,909 | 13,575 |
| Non-cash effect of derivative instruments | — | 514 | 1,928 |
| Amortization of deferred financing costs | 902 | 370 | 968 |
| Other | 271 | 52 | — |
| Changes in operating assets and liabilities, net of acquisition in 2002: | | | |
| Trade accounts receivable | (9,490) | (4,234) | 15,177 |
| Prepaid expenses | (239) | 154 | 6 |
| Fair value of commodity derivative instrument | — | — | (2,442) |
| Other assets | (3,112) | (2,160) | 1,354 |
| Accounts payable and accrued expenses | 4,814 | (21,595) | (6,403) |
| Other liabilities | (949) | (1,930) | 205 |
| Net cash provided by operating activities | 136,702 | 25,417 | 91,847 |
| Cash flows used in investing activities: | | | |
| Acquisition of business, net of cash acquired | (850) | (10,661) | — |
| Property acquisitions | (6,030) | (1,922) | (2,516) |
| Exploration and development expenditures | (103,148) | (42,979) | (119,824) |
| Other property and equipment additions | (608) | (405) | (1,349) |
| Proceeds from sale of oil and gas assets | 579 | 1,587 | 2,622 |
| Net cash used in investing activities | (110,057) | (54,380) | (121,067) |
| Cash flows from financing activities: | | | |
| Bank overdraft | — | (808) | 808 |
| Deferred financing costs | (4,746) | — | — |
| Repayments of long-term debt | (118,362) | (15,541) | (5,172) |
| Proceeds from long-term debt | 15,000 | 48,000 | 30,565 |
| Proceeds from senior notes offering | 150,000 | — | — |
| Proceeds from equity offering, net of commissions | 38,000 | — | — |
| Equity offering costs | (479) | — | — |
| Payment of preferred stock dividends | (2,592) | (2,572) | — |
| Exercise of stock options and warrants | 810 | — | — |
| Other | — | — | (330) |
| Net cash provided by financing activities | 77,631 | 29,079 | 25,871 |
| Net increase (decrease) in cash and cash equivalents | 104,276 | 116 | (3,349) |
| Cash and cash equivalents at beginning of year | 116 | — | 3,349 |
| Cash and cash equivalents at end of year | $ 104,392 | $ 116 | $ — |

See accompanying notes to consolidated financial statements.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

### (1) Organization

Energy Partners, Ltd. was incorporated on January 29, 1998 and is an independent oil and natural gas exploration and production company with operations concentrated in the shallow to moderate depth waters of the Gulf of Mexico Shelf. The Company's future financial condition and results of operations will depend primarily upon prices received for its oil and natural gas production and the costs of finding, acquiring, developing and producing reserves.

### (2) Summary of Significant Accounting Policies

#### *(a) Basis of Presentation*

The consolidated financial statements include the accounts of Energy Partners, Ltd., and its wholly-owned subsidiaries (collectively, the Company). All significant intercompany accounts and transactions are eliminated in consolidation. The Company's interests in oil and natural gas exploration and production ventures and partnerships are proportionately consolidated.

#### *(b) Property and Equipment*

The Company uses the successful efforts method of accounting for oil and natural gas producing activities. Costs to acquire mineral interests in oil and natural gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, and geological and geophysical costs are expensed.

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

The Company calculates the impairment of capitalized costs of proved oil and natural gas properties on a field-by-field basis, utilizing its current estimate of future revenues and operating expenses. In the event net undiscounted cash flow is less than the carrying value, an impairment loss is recorded based on the present value of expected future net cash flows over the economic lives of the reserves.

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depletion, depreciation and amortization are eliminated from the property accounts, and the resulting gain or loss is recognized.

#### *(c) Asset Retirement Obligation*

In 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (Statement 143). Statement 143 requires companies to record the present value of obligations associated with the retirement of tangible long-lived assets in the period in which it is incurred. The liability is capitalized as part of the related long-lived asset's carrying amount. Over time, accretion of the liability is recognized as an operating expense and the capitalized cost is depreciated over the expected useful life of the related asset. The Company's asset retirement obligations relate primarily to the plugging, dismantlement, removal, site reclamation and similar activities of its oil and gas properties. The Company adopted Statement 143 effective January 1, 2003, using the cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation. Prior to adoption of this statement, such obligations were accrued ratably over the productive lives of the assets through its depreciation, depletion and amortization for oil and natural gas properties.

### *(d) Income Taxes*

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

### *(e) Deferred Financing Costs*

Costs incurred to obtain financing are deferred and are being amortized as additional interest expense over the maturity period of the related debt.

### *(f) Earnings Per Share*

Basic earnings per share is computed by dividing income available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed in the same manner as basic earnings per share except that the denominator is increased to include the number of additional common shares that could have been outstanding assuming the exercise of convertible preferred stock shares, warrants and stock option awards and the potential shares that would have a dilutive effect on earnings per share.

### *(g) Revenue Recognition*

The Company uses the entitlement method for recording natural gas sales revenue. Under this method of accounting, revenue is recorded based on the Company's net working interest in field production. Deliveries of natural gas in excess of the Company's working interest are recorded as liabilities and under-deliveries are recorded as receivables. The Company had natural gas imbalance receivables of $1.7 million and $1.3 million at December 31, 2003 and 2002, respectively and had liabilities of $0.5 million at December 31, 2003 and 2002.

### *(h) Statements of Cash Flows*

For purposes of the statements of cash flows, highly-liquid investments with original maturities of three months or less are considered cash equivalents. At December 31, 2003 and 2002, interest-bearing cash equivalents were approximately $110.4 million and $4.4 million, respectively. Exploration expenditures incurred are excluded from operating cash flows and included in investing activities.

### *(i) Hedging Activities*

The Company uses derivative commodity instruments to manage commodity price risks associated with future crude oil and natural gas production, but does not use them for speculative purposes. The Company's commodity price hedging program has utilized financially-settled zero-cost collar contracts to establish floor and ceiling prices on anticipated future crude oil and natural gas production and oil and natural gas swaps to fix the price of anticipated future crude oil and natural gas production. On January 1, 2001, the Company adopted Statement of Financial Accounting Standards No. 133 (Statement 133), as amended, "Accounting for Derivative Instruments and Hedging Activities". Statement 133 establishes accounting and reporting standards requiring 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 is effective, will be recognized in other comprehensive income (a component of stockholders' equity) until settled, when the resulting gains and losses will be recorded in earnings. Hedge ineffectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness, as defined by Statement 133, will be charged currently to earnings.

### *(j) Stock-Based Compensation*

The Company has two stock award plans, the Amended and Restated 2000 Long Term Stock Incentive Plan and the 2000 Stock Option Plan for Non-Employee Directors (the Plans). The Company accounts for its stock-based compensation in accordance with Accounting Principles Board's Opinion No. 25, "Accounting For Stock Issued To Employees" (Opinion No. 25). Statement of Financial Accounting Standards No. 123 (Statement 123), "Accounting For Stock-Based Compensation" and Statement of Financial Accounting Standards No. 148, "Accounting for Stock-Based Compensation — Transition and Disclosure," (Statement 148) permits the continued use of the intrinsic value-based method prescribed by Opinion No. 25, but requires additional disclosures, including pro-forma calculations of earnings and net earnings per share as if the fair value method of accounting prescribed by Statement 123 had been applied. If compensation expense for the Plans had been determined using the fair-value method in Statement 123, the Company's net income (loss) and earnings (loss) per share would have been as shown in the pro forma amounts below (in thousands, except per share amounts):

| | 2003 | 2002 | 2001 |
|---|---|---|---|
| Net income (loss) available to common stockholders: | | | |
| As reported | $32,250 | $ (8,799) | $ 11,974 |
| Pro forma | $28,703 | $(11,364) | $ 10,685 |
| Basic earnings (loss) per share: | | | |
| As reported | $ 0.96 | $ (0.44) | $ 0.45 |
| Pro forma | $ 0.93 | $ (0.53) | $ 0.40 |
| Diluted earnings (loss) per share: | | | |
| As reported | $ 0.93 | $ (0.44) | $ 0.44 |
| Pro forma | $ 0.91 | $ (0.53) | $ 0.40 |
| Average fair value of grants during the year | $ 4.67 | $ 2.72 | $ 3.47 |
| Black-Scholes option pricing model assumptions: | | | |
| Risk free interest rate | 4.5% | 4.5% | 4.5% |
| Expected life (years) | 5 | 5 | 2.5 to 5 |
| Volatility | 47.0 to 49.0% | 35.0% | 35.0% |
| Dividend yield | — | — | — |
| Stock-based employee compensation cost, net of tax, included in net income (loss) as reported | $ 28 | $ 257 | $ 749 |

### *(k) Allowance for Doubtful Accounts*

The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectibility. Many of the Company's receivables are from joint interest owners on properties of which the Company is the operator. Thus, the Company may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. The Company's crude oil and natural gas receivables are typically collected within two months. The Company accrues an allowance on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of any allowance may be reasonably estimated. As of December 31, 2003 and 2002, the Company had an allowance for doubtful accounts of $25,960 and $1.4 million, respectively.

### *(l) Use of Estimates*

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. The Company evaluates its estimates and assumptions on a regular basis. The Company bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, to form the basis for making judgments about carrying values of assets and liabilities that are not readily apparent from other sources. The Company's actual results may differ from these estimates and assumptions used in preparation of its financial statements. Significant estimates with regard to these financial statements and related unaudited disclosures include the estimate of proved oil and natural gas reserve quantities and the related present value of estimated future net cash flows there-from disclosed in note 21.

### *(m) Reclassifications*

Certain reclassifications have been made to the prior period financial statements in order to conform to the classification adopted for reporting in fiscal 2003.

## (3) Common Stock

On November 1, 2000, the Company priced its initial public offering of 5.75 million shares of common stock and commenced trading the following day. On April 16, 2003, the Company completed the public offering of approximately 6.8 million shares of its common stock (the Equity Offering), which was priced at $9.50 per share. The Equity Offering included 4.2 million shares offered by the Company, 1.7 million shares offered by the Company's then principal stockholders, Evercore Capital Partners L.P. and certain of its affiliates (Evercore), and 0.9 million shares offered by Energy Income Fund, L.P. (EIF). In addition, the underwriters exercised their option to purchase 1.0 million additional shares to cover over-allotments, the proceeds from which went to selling shareholders and not to the Company. After payment of underwriting discounts and commissions, the offering generated net proceeds to the Company of approximately $38.0 million. After expenses of approximately $0.5 million, the proceeds were used to repay a portion of outstanding borrowings under the Company's bank credit facility.

In July 2003, Evercore exercised a contractual right to request us to register with the SEC for possible public sale 2.5 million shares of common stock. On August 8, 2003 we were informed by Evercore that it had priced a public offering of the 2.5 million shares of our common stock at $10.40 per share. In October 2003, Evercore, again exercised its contractual right to request the Company to register with the SEC for possible sale of all of Evercore's remaining approximately 4.5 million shares of common stock. On November 11, 2003 the Company was informed by Evercore that it had priced a public offering of all of these remaining shares of the Company's common stock at $11.75 per share. This offering completed the sale of Evercore's interest in the Company. The Company did not sell any shares in the offering and did not receive any proceeds from the shares offered by the selling stockholders.

## (4) Earnings Per Share

Basic earnings per share is computed by dividing income available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed in the same manner as basic earnings per share except that the denominator is increased to include the number of additional common shares that could have been outstanding assuming the exercise of stock options, warrants and convertible preferred stock shares.

The following table reconciles the net earnings and common shares outstanding used in the calculations of basic and diluted earnings per share for the years ended December 31, 2003 and 2001. The diluted loss per share calculation for the year ended December 31, 2002 produces results that are anti-dilutive, therefore, the diluted loss per share amount as reported for this period in the accompanying consolidated statements of operations is the same as the basic loss per share amount.

| | Net Income Available to Common Stockholders | Weighted Average Common Shares Outstanding | Earnings Per Share |
|---|---|---|---|
| | (In thousands, except per share amounts) | | |
| Year ended December 31, 2003: | | | |
| Basic | $29,705 | 30,822 | $0.96 |
| Effect of dilutive securities: | | | |
| Preferred stock | 3,545 | 4,310 | |
| Stock options | — | 235 | |
| Warrants | — | 208 | |
| Diluted | $33,250 | 35,575 | $0.93 |

| | Net Income Available to Common Stockholders | Weighted Average Common Shares Outstanding | Earnings Per Share |
|---|---|---|---|
| | (In thousands, except per share amounts) | | |
| Year ended December 31, 2001: | | | |
| Basic | $11,974 | 26,865 | $0.45 |
| Effect of dilutive securities: | | | |
| Preferred stock | — | — | |
| Stock options | — | 55 | |
| Warrants | — | — | |
| Diluted | $11,974 | 26,920 | $0.44 |

### (5) Supplemental Cash Flow Information

The following is supplemental cash flow information:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | | (In thousands) | |
| Interest paid | $ 5,877 | $4,616 | $ 842 |
| Income taxes paid, net of refunds | $ 76 | $ (29) | $ 79 |

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | (In thousands) | | |
| Accretion of preferred stock | $ 953 | $758 | $— |
| Conversion of preferred stock | $1,418 | $145 | $— |
| Conversion of warrants | $ — | $ — | $ 5 |
| Exercise of options | $1,442 | $ — | $— |

On November 17, 1999, the Company issued a warrant to EIF to purchase 928,050 shares of common stock as required by a financing transaction with Evercore. EIF exercised its option to convert the warrant in January 2001, receiving 466,245 shares of common stock.

### (6) Acquisitions

On January 15, 2002, the Company closed the acquisition of Hall-Houston Oil Company (HHOC). The results of the operations have been included in the Company's consolidated financial statements since that date. HHOC was an oil and natural gas exploration and production company with operations focused in the shallow waters of the Gulf of Mexico. As a result of the acquisition, the Company has a strengthened management team, expanded exploration opportunities as well as a reserve portfolio and production that are more balanced between oil and natural gas.

The HHOC acquisition was completed for consideration consisting of $38.4 million liquidation preference of newly authorized and issued Series D Exchangeable Convertible Preferred Stock (Series D Preferred Stock) with a fair value of $34.7 million discounted to effect the increasing dividend rate, $38.4 million of 11% Senior Subordinated Notes (the Notes), due 2009 (immediately callable at par), 574,931 shares of common stock with a fair value of approximately $3.3 million determined based on the average market price of the Company's common stock over the period of two days before and after the terms of the acquisition were agreed to and announced, $9.0 million of cash including $3.9 million of accrued interest and prepayment fees paid to former debt holders, and warrants to purchase four million shares of the Company's common stock. Of the warrants, one million have a strike price of $9.00 and three million have a strike price of $11.00 per share. The warrants had a fair value of approximately $3.0 million based on a third party valuation and are exercisable beginning January 15, 2003 and expiring on January 15, 2007. In addition, the Company incurred approximately $3.6 million in expenses in connection with the acquisition and assumed HHOC's working capital deficit.

In addition, former preferred stockholders of HHOC have the right to receive contingent consideration. Some of the former stockholders are employees of the Company, however, any contingent consideration payments are not tied to continued employment. The contingent consideration is 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 HHOC as of the closing date of the acquisition (the Ring-Fenced Properties) exceeds the net present value discounted at 30%. The potential consideration is determined annually beginning March 3, 2003 and ending March 1, 2007. The cumulative percentage remitted to the participants is 20% for March 3, 2003, 30% for March 1, 2004, 35% for March 1, 2005, 40% for March 1, 2006 and 50% for March 1, 2007. The contingent consideration, if any, may be paid in the Company's common stock or cash at the Company's option (with a minimum of 20% in cash) and in no event will exceed a value of $50 million. On March 17, 2003, the Company capitalized, as additional purchase price, and paid additional consideration of $0.9 million related to the March 3, 2003 contingent consideration payment date. The Company does not expect the 2004 contingent consideration payment to exceed $2.5 million. Due to the uncertainty inherent in estimating the value of future contingent consideration which includes annual revaluations based upon, among other things, drilling results from the date of the prior revaluation, and development, operating and abandonment costs and production revenues (actual historical and future projected, as contractually defined, as of each revaluation date) for the Ring-Fenced Properties, total final consideration will not be determined until March 1, 2007. All additional contingent consideration will be capitalized as additional purchase price. The following table summarizes the fair value of the assets acquired and liabilities assumed at the date of acquisition:

| | At January 15, 2002 |
|---|---|
| | (In thousands) |
| Current assets | $ 11,157 |
| Property and equipment | 124,031 |
| Deferred taxes | 2,544 |
| Other assets | 909 |
| Total assets acquired | 138,641 |
| Current liabilities | 37,860 |
| Other non-current liabilities | 8,851 |
| Total liabilities assumed | 46,711 |
| Net assets acquired | $ 91,930 |

Following the completion of the acquisition, management of the Company assessed the technical and administrative needs of the combined organization. As a result, 14 redundant positions were eliminated including finance, administrative, geophysical and engineering positions in New Orleans and Houston. Total severance costs under the plan were $1.2 million.

### (7) Property and Equipment

The following is a summary of property and equipment at December 31, 2003 and 2002:

| | 2003 | 2002 |
|---|---|---|
| | (In thousands) | |
| Proved oil and natural gas properties | $584,741 | $458,610 |
| Unproved oil and natural gas properties | 8,716 | 9,180 |
| Other | 4,644 | 4,050 |
| | $598,101 | $471,840 |

Substantially all of the Company's oil and natural gas properties serve as collateral for its bank facility.

### (8) Asset Retirement Obligation

In 2001, the Financial Accounting Standards Board (FASB) issued Statement 143. Statement 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred, a corresponding increase in the carrying amount of the related long-lived asset and is effective for fiscal years beginning after June 15, 2002. The Company adopted Statement 143 effective January 1, 2003, using the cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation. The Company previously recorded estimated costs of dismantlement, removal, site restoration and similar activities as part of its depreciation, depletion and amortization for oil and natural gas properties and recorded a separate liability for such amounts in other liabilities. The effect of adopting Statement 143 on the Company's results of operations and financial condition included a net increase in long-term liabilities of $14.2 million; an increase in net property, plant and equipment of $17.8 million; a cumulative effect of adoption income of $2.3 million, net of deferred income taxes of $1.3 million.

The pro forma asset retirement obligations would have been $26.0 million at January 1, 2002 and $36.9 million at December 31, 2002 had the Company adopted Statement 143 on January 1, 2002. The following pro forma data summarizes the Company's net loss and net loss per share as if the Company had adopted the provisions of Statement 143 on January 1, 2002 (in thousands, except per share amounts):

| | Year Ended December 31, 2002 | Year Ended December 31, 2001 |
|---|---|---|
| Net loss available to common stockholders, as reported | $(12,129) | $ 11,974 |
| Pro forma adjustments to reflect retroactive adoption of Statement 143 | (172) | 2,232 |
| Pro forma net loss | $(12,301) | $ 14,206 |
| Net loss per share: | | |
| Basic — as reported | $ (0.44) | $ 0.45 |
| Basic — pro forma | $ (0.45) | $ 0.53 |
| Diluted — as reported | $ (0.44) | $ 0.45 |
| Diluted — pro forma | $ (0.45) | $ 0.53 |

The following table reconciles the beginning and ending aggregate recorded amount of the asset retirement obligation for the year ended December 31, 2003 (in thousands):

| | Asset Retirement Obligation |
|---|---|
| December 31, 2002 | $22,669 |
| Net impact of initial adoption | 14,211 |
| Accretion expense | 1,963 |
| Liabilities incurred | 812 |
| Liabilities settled | (1,597) |
| Revisions in estimated cash flows | 2,519 |
| December 31, 2003 | $40,577 |

## (9) Long-Term Debt

On August 5, 2003, the Company 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 buyers. In October 2003, the Company consummated an exchange offer pursuant to which it exchanged registered Senior Notes having substantially identical terms as the Senior Notes for the privately placed Senior Notes. After discounts and commissions and all offering expenses, the Company received $145.3 million, which was used to redeem all of the outstanding 11% Senior Subordinated Notes Due 2009 (see note 6) and to repay substantially all of the borrowings outstanding under the Company's bank credit facility. The remainder of the net proceeds will be used for general corporate purposes, including acquisitions.

The Senior Notes mature on August 1, 2010 with interest payable each February 1 and August 1, commencing February 1, 2004. The indenture relating to the Senior Notes contains certain restrictions on the Company's ability to incur additional debt, pay dividends on its common stock, make investments, create liens on its assets, engage in transactions with its affiliates, transfer or sell assets and consolidate or merge substantially all of its assets. The Senior Notes are not subject to any sinking fund requirements.

On July 28, 2003 the Company amended its bank credit facility in connection with the Debt Offering. The amendment reduced the borrowing base under the bank credit facility to $60 million upon consummation of the Debt Offering. The borrowing base is subject to redetermination based on the proved reserves of the oil and gas properties that serve as collateral for the bank facility as set out in the reserve report delivered to the banks each April 1 and October 1. The bank facility is available through March 30, 2005 with interest permitted at both prime rate based borrowings and London interbank borrowing rate (LIBOR) borrowings plus a floating spread. The spread will float up or down based on our utilization of the bank facility. The spread can range from 0% to 0.75% above prime and 1.5% to 2.25% above LIBOR. Indebtedness under the bank facility is secured by substantially all of the assets of the Company. 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 weighted average interest rate at December 31, 2003 and 2002 was 4.00% and 3.18%, respectively. The bank credit facility contains customary events of default and various financial covenants which required the Company to: (i) maintain a minimum current ratio of 1.1, (ii) maintain a minimum EBITDAX to interest ratio of 5.00 times, and (iii) maintain a minimum tangible net worth as calculated in accordance with the agreement. The Company was in compliance with these covenants at December 31, 2003.

Total long-term debt outstanding at December 31, 2003 and 2002 were as follows:

| | 2003 | 2002 |
|---|---|---|
| | (In thousands) | |
| Senior Notes, annual interest of 8.75%, payable August 1, 2010 | $150,000 | $ — |
| Bank facility, interest rate based on prime and LIBOR borrowing rates plus a floating spread payable March 30, 2005, with weighted average interest on December 31, 2003 of 4.00% | 100 | 65,000 |
| The Notes, annual interest of 11%, due January 15, 2009 | — | 38,371 |
| Financing note payable, annual interest of 7.99%, equal monthly payments, maturing February 2006 | 316 | 408 |
| | 150,416 | 103,779 |
| Less: Current maturities | 99 | 92 |
| | $150,317 | $103,687 |

Maturities of long-term debt as of December 31, 2003 were as follows (in thousands):

| | |
|---|---|
| 2004 | $ 99 |
| 2005 | 208 |
| 2006 | 109 |
| 2007 | — |
| 2008 | — |
| Thereafter | 150,000 |
| | $150,416 |

## (10) Redeemable Preferred Stock

In connection with the acquisition of HHOC, in January 2002, the Company authorized 550,000 shares of Series D Preferred Stock, having a par value of $1.00 per share, of which 383,707 shares were issued in the acquisition of HHOC.

The Series D Preferred Stock earns cumulative dividends payable semiannually in arrears on June 30 and December 31 of each year as follows:

| Dividend Period Ending | Dividend Rate |
|---|---|
| June 30, 2002 to December 31, 2004 | 7% |
| June 30, 2005 to December 31, 2005 | 8% |
| June 30, 2006 to December 31, 2006 | 9% |
| June 30, 2007 and thereafter | 10% |

Any dividends accrued on or prior to December 31, 2005 shall, when declared, be payable in cash at the dividend rate per-share based on the stated value of $100. Any dividends accrued after December 31, 2005 and on or before December 31, 2008 shall, when declared, be payable, at the option of the Company, either in cash at the dividend rate per-share based on the stated value of $100 or by issuing dividend shares having an aggregate value equal to the dividend rate per-share based on the stated value of $100. The Company may, at its option on or after December 31, 2004, redeem the Series D Preferred Stock in whole, at a redemption price per-share equal to $100 plus accrued and unpaid dividends. The Company may also, at its option, on any dividend payment date, exchange the Series D Preferred Stock, in whole, along with any unpaid dividends, for an equal principal amount of Exchangeable Notes. At the time of the exchange, holders of outstanding shares will be entitled to receive $100 principal amount of Exchangeable Notes for each $100 stated value of Series D Preferred Stock and accrued and unpaid dividends. The Exchangeable Notes mature January 15, 2009 and the coupon follows the same schedule as that of the dividends on the Series D Preferred Stock. Each share of the Series D Preferred Stock is convertible at the option of the record holder at any time, into the number of shares of common stock determined by dividing $100 by the conversion price of $8.54 as adjusted pursuant to the terms of the Series D Preferred Stock designation. In 2003, 14,184.9 shares of Series D Preferred Stock were converted into 166,095 shares of common stock and in 2002, 1,445.8 shares of Series D Preferred Stock were converted into 16,929 shares of common stock.

## (11) Significant Customers

The Company had oil and natural gas sales to two customers accounting for approximately 30 percent and 10 percent, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2003. The Company had oil and natural gas sales to three customers accounting for approximately 41 percent, 27 percent and 11 percent, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2002. The Company had oil and natural gas sales to three customers accounting for 38 percent, 37 percent and 15 percent, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2001.

## (12) Hedging Activities

The Company enters into hedging transactions with major financial institutions to reduce exposure to fluctuations in the price of oil and natural gas. Any gains or losses resulting from these hedging transactions are recorded in other revenue in the statements of operations. Crude oil hedges are settled based on the average of the reported settlement prices for West Texas Intermediate crude on the NYMEX for each month. Natural gas hedges are settled based on the average of the last three days of trading of the NYMEX Henry Hub natural gas contract for each month. The Company also uses financially-settled crude oil and natural gas swaps, zero-cost collars and options used to provide floor prices with varying upside price participation.

On December 12, 2001, the Company purchased a financially-settled put swaption (put swaption) in anticipation of the acquisition of Hall-Houston Oil Company and affiliated interests (collectively, HHOC). The put swaption provided the Company with a financially-settled natural gas swap at $2.95 per Mmbtu for 10,950,000 Mmbtu (30,000 Mmbtu per day) for the period of February 2002 through January 2003 and the option to cancel this swap on January 15, 2002. The cost to enter into the contract was $2.4 million. On January 15, 2002, the Company exercised its right provided by the put swaption to retain the swap at $2.95 per Mmbtu.

With a financially-settled swap, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the hedged price for the transaction, and the Company is 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 the Company if the settlement price for any settlement period is below the floor price of the collar, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the cap price for the collar. In some hedges we may modify our collar to provide full upside participation after a limited non-participation range.

The Company had the following hedging contracts as of December 31, 2003:

**Natural Gas Positions**

| | | | Volume (Mmbtu) | |
|---|---|---|---|---|
| Remaining Contract Term | Contract Type | Strike Price ($/Mmbtu) | Daily | Total |
| 01/04 | Collar | $3.50/$5.40 | 10,000 | 310,000 |
| 01/04 | Collar | $3.50/$5.25 | 10,000 | 310,000 |
| 01/04 — 06/04 | Collar | $4.00/$7.00 | 10,000 | 1,820,000 |
| 01/04 — 12/04 | Collar | $4.00/$6.50 | 10,000 | 3,660,000 |
| 02/04 — 12/04 | Collar | $3.50/$8.00 | 10,000 | 3,350,000 |

**Crude Oil Positions**

| | | | Volume (Bbls) | |
|---|---|---|---|---|
| Remaining Contract Term | Contract Type | Strike Price ($/Bbl) | Daily | Total |
| 01/04 — 12/04 | Swap | $27.35 | 1,500 | 549,000 |
| 01/04 — 06/04 | Collar | $25.00/$31.38 | 1,500 | 273,000 |
| 07/04 — 09/04 | Collar | $24.00/$29.00 | 1,500 | 138,000 |
| 10/04 — 12/04 | Collar | $24.00/$28.75 | 1,500 | 138,000 |

For the years ended December 31, 2003, 2002 and 2001, hedging activities reduced oil and gas revenues by $11.5, $5.0 and $3.5 million, respectively.

The following table reconciles the change in accumulated other comprehensive income for the years ended December 31, 2003 and 2002:

| | Year Ended December 31, 2003 | |
|---|---|---|
| | (In thousands) | |
| Accumulated other comprehensive loss as of December 31, 2002 | | $(2,171) |
| Net income | $33,250 | |
| Other comprehensive income — net of tax | | |
| Hedging activities | | |
| Reclassification adjustments for settled contracts | 7,359 | |
| Changes in fair value of outstanding hedging positions | (7,629) | |
| Total other comprehensive income | (270) | (270) |
| Comprehensive income | $32,710 | |
| Accumulated other comprehensive loss as of December 31, 2003 | | $(2,441) |

| | Year Ended December 31, 2002 | |
|---|---|---|
| | (In thousands) | |
| Accumulated other comprehensive income as of December 31, 2001 | | $ 981 |
| Net loss | $ (8,799) | |
| Other comprehensive loss — net of tax | | |
| Hedging activities | | |
| Reclassification adjustments for settled contracts | 3,243 | |
| Changes in fair value of outstanding hedging positions | (6,395) | |
| Total other comprehensive loss | (3,152) | (3,152) |
| Comprehensive loss | $(11,951) | |
| Accumulated other comprehensive loss as of December 31, 2002 | | $(2,171) |

Based upon current prices, the Company expects to transfer approximately $3.8 million of pretax net deferred losses in accumulated other comprehensive income as of December 31, 2003 to earnings during 2004 when the forecasted transactions actually occur.

## (13) Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2003 and 2002. The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties. The table excludes cash and cash equivalents, trade accounts receivable, noncurrent assets, trade accounts payable and accrued expenses and derivative instruments, all of which had fair values approximating carrying amounts. The fair value of current and long-term debt is estimated based on current rates offered the Company for debt of the same maturities. The Company has off-balance sheet exposures relating to certain financial guarantees and letters of credit. The fair value of these, which represents fees associated with obtaining the instruments, was nominal.

| | 2003 | | 2002 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| | (In thousands) | | | |
| Financial liabilities: | | | | |
| Current and long-term debt: | | | | |
| The Senior Notes | $150,000 | $156,000 | $ — | $ — |
| Bank credit facility | 100 | 100 | 65,000 | 65,000 |
| The Notes | — | — | 38,371 | 41,420 |
| Financing note payable | 316 | 316 | 408 | 408 |

## (14) Income Taxes

Components of income tax expense (benefit) for the years ended December 31, 2003, 2002 and 2001 are as follows:

| | Current | Deferred (In thousands) | Total |
|---|---|---|---|
| 2003: | | | |
| Federal | $ 76 | $16,701 | $16,777 |
| State | — | 1,007 | 1,007 |
| | $ 76 | $17,708 | $17,784 |
| 2002: | | | |
| Federal | $(29) | $(4,393) | $(4,422) |
| State | — | (260) | (260) |
| | $(29) | $(4,653) | $(4,682) |
| 2001: | | | |
| Federal | $ 79 | $ 6,628 | $ 6,707 |
| State | — | 395 | 395 |
| | $ 79 | $ 7,023 | $ 7,102 |

The reasons for the differences between the effective tax rates and the "expected" corporate federal income tax rate of 34% is as follows:

| | Percentage of Pretax Earnings | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| Expected tax rate | 34.0% | (34.0)% | 34.0% |
| Stock-based compensation | 0.6 | 1.0 | 1.1 |
| State taxes | 2.1 | (1.9) | 2.1 |
| Other | (0.2) | 0.2 | — |
| | 36.5% | (34.7)% | 37.2% |

The tax effects of temporary differences that give rise to significant portions of the current tax asset and net deferred tax liability at December 31, 2003 and 2002 are presented below:

| | 2003 | 2002 |
|---|---|---|
| | (In thousands) | |
| Current deferred tax assets: | | |
| Fair value of commodity derivative instruments | $ 1,373 | $ 1,221 |
| Accrued bonus compensation | 1,566 | — |
| Current deferred tax assets | $ 2,939 | $ 1,221 |
| Deferred tax assets: | | |
| Restricted stock awards and options | $ 810 | $ 1,074 |
| Federal and state net operating loss carryforwards | 18,559 | 17,358 |
| Other | 439 | 220 |
| Deferred tax liability: | | |
| Property, plant and equipment, principally due to differences in depreciation | (49,392) | (27,685) |
| Net non-current deferred tax liability | $(29,584) | $ (9,033) |

At December 31, 2003, the Company had net operating loss carryforwards of approximately $52.8 million, which are available to reduce future federal taxable income. The net operating loss carryforwards begin expiring in the years 2018 through 2022. Although realization is not assured, management believes it is more likely than not that all of the deferred tax assets will be realized through future earnings and, reversal of taxable temporary differences. As a result, no valuation allowance has been provided.

## (15) Employee Benefit Plans

The Company has a long term incentive plan authorizing various types of market and performance based incentive awards which may be granted to officers and employees. The Amended and Restated 2000 Long Term Stock Incentive Plan (the Plan) provides for the grant of stock options for which the exercise price, set at the time of the grant, is not less than the fair market value per share at the date of grant. The options have a term of 10 years and generally vest over 3 years. The Plan also provides for restricted stock and performance share awards. The amended plan was approved by stockholders on May 9, 2002 and is administered by the Compensation Committee of the board of directors or such other committee as may be designated by the board of directors. The Compensation Committee is authorized to select the employees of the Company and its subsidiaries and affiliates who will receive awards, to determine the types of awards to be granted to each person, and to establish the terms of each award. The total number of shares that may be issued under the plan for all types of awards is 4,800,000.

In April 2000, an employee, pursuant to her employment agreement, was granted 90,000 shares of restricted stock and stock options to purchase 375,000 shares of common stock. The restricted stock granted became fully vested in 2002. The stock options vest and are exercisable at the prices as follows: 150,000 shares at $7.67 per share in April 2001, 150,000 shares at $8.82 per share in April 2002 and the remaining shares at $10.14 in April 2003. The grant date fair value of the restricted stock and options was $17.00.

The Company issued 131,754 and 92,990 shares of common stock as restricted stock awards in 2003 and 2002, respectively, to certain employees and officers. The restrictions on this stock generally lapse on the second and third anniversary of the date of grant and require that the employee remain employed by the Company during the vesting period. The weighted average grant-date fair value of restricted shares granted in the years ended December 31, 2003 and 2002 was approximately $10.12 and $8.19, respectively.

The Company has recognized non-cash compensation expense of $0.8 million, $0.5 million and $1.7 million in 2003, 2002 and 2001, respectively, related to the restricted stock and stock option grants. At December 31, 2003, there was $1.1 million of deferred stock based compensation expense related to the restricted stock awards, which will be recognized over the remaining vesting periods.

In 2003, 141,500 performance shares were awarded and 13,333 were forfeited, leaving 128,167 performance shares outstanding at December 31, 2003. These shares cliff vest at the end of three years and are based on the attainment of certain performance goals. The expected fair value of the shares on the vesting date is charged to expense ratably over the vesting period unless it is determined that the performance goals will not be met. The Company recognized non-cash compensation expense of $0.5 million related to these awards in 2003.

The board of directors also adopted the 2000 Stock-Option Plan for Non-Employee Directors on September 12, 2000, and the stockholders approved the plan on September 15, 2000. The plan provides for automatic grants of stock options to members of the board of directors who are not employees of the Company or any subsidiary. An initial grant of a stock option to purchase 4,000 shares of our common stock was made to each non-employee director upon consummation of the public offering. An initial grant of a stock option to purchase 2,000 shares will also be made to each person who becomes a non-employee director after the effective date upon his or her initial election or appointment. After the initial grant, each non-employee director will receive an additional grant of a stock option to purchase 4,000 shares of our common stock immediately following each subsequent annual meeting. All stock options granted under the plan will have a per share exercise price equal to the fair market value of a share of common stock on the date of grant (as determined by the committee appointed to administer the plan), will be fully vested and immediately exercisable, and will expire on the earlier of (i) ten years from the date of grant or (ii) 36 months after the optionee ceases to be a director for any reason. For initial grants, fair market value was the public offering price. The total number of shares of our common stock that may be issued under the plan is 250,000, subject to adjustment in the case of certain corporate transactions and events.

A summary of stock options granted under the incentive plans for the years ended December 31, 2003, 2002 and 2001 are as follows:

| | 2003 | | 2002 | | 2001 | |
|---|---|---|---|---|---|---|
| | Number of Shares | Weighted Average Exercise Price | Number of Shares | Weighted Average Exercise Price | Number of Shares | Weighted Average Exercise Price |
| Outstanding at beginning of year | 1,997,965 | $ 9.30 | 1,094,282 | $10.76 | 568,097 | $10.77 |
| Granted | 519,200 | $10.18 | 1,110,426 | $ 7.96 | 585,808 | $10.93 |
| Exercised | (232,871) | $ 7.98 | — | $ — | — | $ — |
| Forfeited | (275,012) | $ 8.87 | (206,743) | $ 9.85 | (59,623) | $12.57 |
| Outstanding at end of year | 2,009,282 | $ 9.68 | 1,997,965 | $ 9.30 | 1,094,282 | $10.76 |
| Exercisable at end of year | 840,027 | $10.13 | 551,349 | $10.16 | 253,194 | $10.15 |
| Available for future grants | 2,584,978 | | 2,869,045 | | 1,782,848 | |

A summary of information regarding stock options outstanding at December 31, 2003 is as follows:

| | Options Outstanding | | | Options Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Prices | Shares | Remaining Contractual Life | Weighted Average Price | Shares | Weighted Average Price |
| $7.10 - $10.55 | 1,476,332 | 7.7 years | $ 8.85 | 562,446 | $ 8.77 |
| $10.55 - $15.00 | 532,950 | 7.3 years | $11.99 | 277,581 | $12.90 |

The Company also has a 401(k) Plan (the Plan) that covers all employees. The Plan was amended in 2002 such that, commencing July 1, 2002 the Company matches 50% of each individual participant's contribution not to exceed 2% of the participant's compensation. The contributions may be in the form of cash or the Company's common stock. The Company made matching contributions to the Plan of 15,343 and 9,206 shares of common stock in 2003 and 2002 valued at approximately $175,000 and $84,000, respectively.

### (16) Commitments and Contingencies

The Company has operating leases for office space and equipment, which expire on various dates through 2011. In addition, the Company has agreed to purchase seismic-related services which expire on various dates through 2005.

Future minimum commitments as of December 31, 2003 under these operating obligations are as follows (in thousands):

| | |
|---|---|
| 2004 | $ 3,945 |
| 2005 | 5,961 |
| 2006 | 2,870 |
| 2007 | 1,960 |
| 2008 | 1,971 |
| Thereafter | 3,479 |
| | $20,186 |

Rent expense for the years ended December 31, 2003, 2002 and 2001 was $3.7 million, $3.3 million and $1.8 million, respectively.

Commencing January 1, 2002, the Company has been required to make monthly deposits of $250,000 into a trust for future abandonment costs at East Bay. The Company is not entitled to access the trust fund in order to draw funds for abandonment purposes prior to December 31, 2003. Monthly deposits are not required to be made for fiscal year 2004 and are to resume January 1, 2005, however, beginning December 31, 2003 the minimum balance in the trust must be maintained at $6.0 million until such time that the remaining abandonment obligation is less than that amount. Therefore if funds are drawn to pay for ongoing abandonment activities, deposits may be necessary. These deposits are classified as other assets in the accompanying consolidated balance sheets.

In February 2003, the Company settled a lawsuit filed in 2001 for $2 million. This settlement is reflected in general and administrative expenses in 2002. From time to time, the Company is involved in litigation arising out of operations in the normal course of business. In management's opinion, the Company is not involved in any litigation, the outcome of which would have a material effect on the financial position, results of operations or liquidity of the Company.

### (17) Related Party

The Company's Chairman, President and Chief Executive Officer serves on the board of directors of a company that provides contract operations and other oilfield equipment and services to the Company. The Company incurred gross costs, both capital and lease operating on behalf of itself and its working interest partners, from this service provider of approximately $4.2 million, $4.0 million and $4.2 million in 2003, 2002 and 2001, respectively. Loss of this service provider would not have a material adverse effect on the operations of the Company.

Pursuant to the Company's stockholder agreement with Evercore, the Company paid an affiliate of Evercore a monitoring fee of $250,000 for each of the years 2003, 2002 and 2001. The requirement to pay this fee ceased in November 2003 when Evercore's beneficial ownership of the Company's stock became less than

10%. An affiliate of Evercore provided investment-banking advisory services to the Company in relation to the January 2002 acquisition of HHOC. The Company paid $0.4 million for these services in 2002.

Certain officers and their affiliates that held interests prior to the HHOC transaction continue to be royalty owners in individual properties acquired from HHOC and operated by the Company.

### (18) *Interim Financial Information (Unaudited)*

The following is a summary of consolidated unaudited interim financial information for the years ended December 31, 2003 and 2002:

| | Three Months Ended | | | |
|---|---|---|---|---|
| | March 31 | June 30 | September 30 | December 31 |
| | (In thousands, except per share data) | | | |
| **2003** | | | | |
| Revenues | $57,237 | $54,219 | $58,879 | $59,852 |
| Costs and expenses | 36,832 | 40,572 | 45,293 | 48,930 |
| Income from operations | 20,405 | 13,647 | 13,586 | 10,922 |
| Net income | 14,182 | 7,564 | 6,724 | 4,780 |
| Net income available to common stockholders | 13,327 | 6,611 | 5,841 | 3,926 |
| Earnings per share: | | | | |
| Basic | $ 0.48 | $ 0.21 | $ 0.18 | $ 0.12 |
| Diluted | 0.44 | 0.21 | 0.18 | 0.12 |
| **2002** | | | | |
| Revenues | $29,125 | $36,863 | $33,678 | $34,122 |
| Costs and expenses | 36,646 | 34,237 | 35,829 | 33,676 |
| Income (loss) from operations | (7,521) | 2,626 | (2,151) | 446 |
| Net income (loss) | (5,814) | 466 | (2,556) | (875) |
| Net loss available to common stockholders | (6,538) | (421) | (3,432) | (1,738) |
| Loss per share: | | | | |
| Basic | $ (0.24) | $ (0.02) | $ (0.12) | $ (0.06) |
| Diluted | (0.24) | (0.02) | (0.12) | (0.06) |

### (19) Supplemental Condensed Consolidating Financial Information

In connection with the Debt Offering, discussed above, all of the Company's current active subsidiaries (the Guarantor Subsidiaries) jointly, severally and unconditionally guaranteed the payment obligations under the Debt Offering. The following supplemental financial information sets forth, on a consolidating basis, the balance sheet, statement of operations and cash flow information for Energy Partners, Ltd. (Parent Company Only) and for the Guarantor Subsidiaries. The Company has not presented separate financial statements and other disclosures concerning the Guarantor Subsidiaries because management has determined that such information is not material to investors.

The supplemental condensed consolidating financial information has been prepared pursuant to the rules and regulations for condensed financial information and does not include all disclosures included in annual financial statements, although the Company believes that the disclosures made are adequate to make the information presented not misleading. Certain reclassifications were made to conform all of the financial information to the financial presentation on a consolidated basis. The principal eliminating entries eliminate investments in subsidiaries, intercompany balances and intercompany revenues and expenses.

## Supplemental Condensed Consolidating Balance Sheet
## As of December 31, 2003

| | Parent Company Only | Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|
| | | (In thousands) | | |
| **ASSETS** | | | | |
| Current assets: | | | | |
| Cash and cash equivalents | $104,392 | $ — | $ — | $104,392 |
| Trade accounts receivable | 34,914 | 401 | — | 35,315 |
| Other current assets | 5,314 | (269) | — | 5,045 |
| Total current assets | 144,620 | 132 | — | 144,752 |
| Property and equipment | 419,620 | 178,480 | — | 598,100 |
| Less accumulated depreciation, depletion and amortization | (143,392) | (66,620) | — | (210,012) |
| Net property and equipment | 276,228 | 111,860 | — | 388,088 |
| Investment in affiliates | 76,829 | — | (76,829) | — |
| Notes receivable, long-term | — | 69,000 | (69,000) | — |
| Other assets | 11,341 | — | — | 11,341 |
| | $509,018 | $180,892 | $(145,829) | $544,181 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | | | |
| Current liabilities: | | | | |
| Accounts payable and accrued expenses | $ 56,898 | $ 240 | $ — | $ 57,138 |
| Fair value of commodity derivative instruments | 3,814 | — | — | 3,814 |
| Current maturities of long-term debt | — | 99 | — | 99 |
| Total current liabilities | 60,712 | 339 | — | 61,051 |
| Long-term debt | 150,100 | 69,217 | (69,000) | 150,317 |
| Other liabilities | 36,721 | 34,607 | — | 71,328 |
| | 247,533 | 104,163 | (69,000) | 282,696 |
| Stockholders' equity: | | | | |
| Preferred stock | 34,894 | — | — | 34,894 |
| Common stock | 323 | — | — | 323 |
| Additional paid-in capital | 228,511 | — | — | 228,511 |
| Accumulated other comprehensive loss | (2,441) | — | — | (2,441) |
| Retained earnings | 198 | 76,829 | (76,829) | 198 |
| Total stockholders' equity | 261,485 | 76,829 | (76,829) | 261,485 |
| | $509,018 | $180,892 | $(145,829) | $544,181 |

**Supplemental Condensed Consolidating Statement of Operations**
**Year Ended December 31, 2003**

| | Parent Company Only | Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|
| | | (In thousands) | | |
| Revenue: | | | | |
| Oil and gas | $149,665 | $80,038 | $ — | $229,703 |
| Other | 26,351 | 254 | (26,121) | 484 |
| | 176,016 | 80,292 | (26,121) | 230,187 |
| Costs and expenses: | | | | |
| Lease operating expenses | 19,755 | 16,938 | — | 36,693 |
| Taxes, other than on earnings | 492 | 7,158 | — | 7,650 |
| Exploration expenditures | 15,237 | 2,116 | — | 17,353 |
| Depreciation, depletion and amortization | 63,215 | 18,712 | — | 81,927 |
| General and administrative | 27,859 | 15,145 | (15,000) | 28,004 |
| Total costs and expenses | 126,558 | 60,069 | (15,000) | 171,627 |
| Income from operations | 49,458 | 20,223 | (11,121) | 58,560 |
| Interest expense, net | (9,823) | 29 | — | (9,794) |
| Income before income taxes and cumulative effect of change in accounting principle | 39,635 | 20,252 | (11,121) | 48,766 |
| Income taxes | (17,784) | — | — | (17,784) |
| Income before cumulative effect of change in accounting principle | 21,851 | 20,252 | (11,121) | 30,982 |
| Cumulative effect of change in accounting principle | 11,399 | (9,131) | — | 2,268 |
| Net income | $ 33,250 | $11,121 | $(11,121) | $ 33,250 |

**Supplemental Condensed Consolidating Statement of Cash Flows**
**Year Ended December 31, 2003**

| | Parent Company Only | Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|
| | | (In thousands) | | |
| Net cash provided by operating activities | $ 113,307 | $ 34,395 | $(11,000) | $ 136,702 |
| Cash flows used in investing activities: | | | | |
| Acquisition of business, net of cash acquired | (850) | — | — | (850) |
| Property acquisitions | (6,028) | (2) | — | (6,030) |
| Exploration and development expenditures | (79,852) | (23,296) | — | (103,148) |
| Other property and equipment additions | (603) | (5) | — | (608) |
| Proceeds from the sale of oil and natural gas assets | 579 | — | — | 579 |
| Net cash used in investing activities | (86,754) | (23,303) | — | (110,057) |
| Cash flows provided by (used in) financing activities: | | | | |
| Deferred financing costs | (4,746) | — | — | (4,746) |
| Repayments of long-term debt | (118,270) | (11,092) | 11,000 | (118,362) |
| Equity offering costs | (479) | — | — | (479) |
| Proceeds from public offering net of commissions | 38,000 | — | — | 38,000 |
| Proceeds from senior notes offering | 150,000 | — | — | 150,000 |
| Proceeds from long-term debt | 15,000 | — | — | 15,000 |
| Dividends paid | (2,592) | — | — | (2,592) |
| Exercise of stock options and warrants | 810 | — | — | 810 |
| Net cash provided by (used in) financing activities | 77,723 | (11,092) | 11,000 | 77,631 |
| Net increase in cash and cash equivalents | 104,276 | — | — | 104,276 |
| Cash and cash equivalents at the beginning of the period | 116 | — | — | 116 |
| Cash and cash equivalents at the end of the period | $ 104,392 | $ — | $ — | $ 104,392 |

### (20) New Accounting Policies

In November 2002, the FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 requires a company to recognize a liability for the obligations it has undertaken in issuing a guarantee. This liability would be recorded at the inception of a guarantee and would be measured at fair value. The measurement provisions of this statement apply prospectively to guarantees issued or modified after December 31, 2002. The disclosure provisions apply to financial statements for periods ending after December 15, 2002. The Company does not currently have guarantees that require disclosure. The Company has adopted FIN 45, which did not have an impact on the financial position, results of operations or cash flows of the Company.

In December 2003, the FASB issued FASB Interpretation 46 (Revised December 2003), "Consolidation of Variable Interest Entities," (FIN 46R) which addresses how a business enterprise should evaluate whether it has a controlling financial interest in an entity through means other than voting rights and accordingly should consolidate the entity. FIN 46R replaces FASB Interpretation 46, "Consolidation of Variable Interest Entities," which was issued in January 2003. The Company will be required to apply FIN 46R to variable interests in variable interest entities (VIEs) no later than March 31, 2004. The Company has assessed the impact of FIN 46R, which will not currently have an impact on the financial position, results of operations or cash flows of the Company.

During the second quarter of 2002, the FASB issued Statement 145, Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections (Statement 145). This statement rescinds SFAS No. 4, Reporting Gains and Losses from Extinguishments of Debt, and requires that all gains and losses from extinguishments of debt should be classified as extraordinary items only if they meet the criteria of in APB No. 30. Applying APB No. 30 will distinguish transactions that are part of an entity's recurring operations from those that are unusual or infrequent or that meet the criteria for classification as an extraordinary item. Any gain or loss on extinguishment of debt that was classified as an extraordinary item in prior periods presented that does not meet the criteria in APB No. 30 for classification as an extraordinary item must be reclassified. The Company has adopted Statement 145, which did not have an impact on the financial position, results of operations or cash flows of the Company.

In June 2002, the FASB issued Statement 146, Accounting for Costs Associated with Exit or Disposal Activities (Statement 146). Statement 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and requires that liabilities associated with these costs be recorded at their fair value in the period in which the liability is incurred. Statement 146 became effective for disposal activities initiated after December 31, 2002. The Company adopted Statement 146, which did not have an impact on the financial position, results of operations or cash flows of the Company.

In December 2002, the FASB issued Statement 148, "Accounting for Stock-Based Compensation — Transition and Disclosure" (Statement 148). Statement 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, Statement 148 amends the disclosure requirements of Statement 123, "Accounting for Stock-Based Compensation," to require more prominent and frequent disclosures in financial statements about the effects of stock-based compensation. The transition guidance and annual disclosure provisions of Statement 148 are effective for fiscal years ending after December 15, 2002, while the interim disclosure provisions are effective for periods beginning after December 15, 2002. Disclosures required by Statement 148 are included in these notes to the consolidated financial statements.

On April 30, 2003, the FASB issued Statement of Financial Accounting Standards No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities (Statement 149). Statement 149 amends and clarifies the accounting guidance on (1) derivative instruments (including certain derivative instruments embedded in other contracts) and (2) hedging activities that fall within the scope of FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities (Statement 133). Statement 149 also amends certain other existing pronouncements, which will result in more consistent reporting of contracts that are derivatives in their entirety or that contain embedded derivatives that warrant separate accounting. Statement 149 is effective (1) for contracts entered into or modified after June 30, 2003, with certain exceptions, and (2) for hedging relationships designated after June 30, 2003. The guidance is to be applied prospectively. The Company has adopted Statement 149, which did not have an impact on its financial position, results of operations or cash flows.

In May 2003, the FASB issued Statement of Financial Accounting Standards No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity (Statement 150). Statement 150 establishes standards for how an issuer classifies and measures in its statement of financial position certain financial instruments with characteristics of both liabilities and equity. In accordance with the standard, financial instruments that embody obligations for the issuer are required to be classified as liabilities. Statement 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise shall be effective at the beginning of the first interim period beginning after June 15, 2003. The Company has adopted Statement 150, which did not have an impact on its financial position, results of operations or cash flows.

Statement of Financial Accounting Standards No. 141, "Business Combinations," (Statement 141) and No. 142, "Goodwill and Intangible Assets," (Statement 142) became effective for the Company on July 1, 2001 and January 1, 2002, respectively. Statement 141 requires all business combinations initiated after June 30, 2001, to be accounted for using the purchase method. Additionally, Statement 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. Statement 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under Statement 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. The appropriate application of Statement 141 and 142 to oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves is unclear. Depending on how the accounting and disclosure literature is clarified, these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds may be classified separately from oil and gas properties, as intangible assets on the Company's balance sheets. Additional disclosures required by Statements 141 and 142 would be included in the notes to financial statements. Historically, the Company, like many other oil and gas companies, have included these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves as part of the oil and gas properties, even after Statements 141 and 142 became effective.

This interpretation of Statements 141 and 142 would affect only the Company's balance sheet classification of oil and natural gas leaseholds. The results of operations and cash flows would not be affected, since these oil and natural gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves would continue to be amortized in accordance with accounting rules for oil and natural gas companies provided in Statement of Financial Accounting Standards No. 19 "Financial Accounting and Reporting by Oil and Gas Producing Companies."

At December 31, 2003, the Company had unproved and proved leasehold of approximately $5 million and $100 million that would have been classified on the balance sheet as unproved intangible oil and natural gas properties and intangible acquired proved leaseholds, respectively, if the Company had applied the interpretation currently being deliberated by the Emerging Issues Task Force (EITF). The Company will continue to classify oil and natural gas leaseholds as oil and natural gas properties until further guidance is provided.

### (21) Supplementary Oil and Natural Gas Disclosures — (Unaudited)

Our December 31, 2003 and 2002 estimates of proved reserves are based on reserve reports prepared by Netherland, Sewell & Associates, Inc. and Ryder Scott Company, L.P., independent petroleum engineers, and the December 31, 2001 estimates are based on a reserve report prepared by Netherland, Sewell & Associates, Inc. Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" natural gas and crude oil reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures. Proved reserves are estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved-developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

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

| | Crude Oil (Mbbls) | Natural Gas (Mmcf) |
|---|---|---|
| Proved-developed and undeveloped reserves: | | |
| December 31, 2000 | 27,521 | 49,150 |
| Purchase of reserves in place | 117 | 301 |
| Extensions, discoveries and other additions | 2,797 | 28,383 |
| Revisions | (1,192) | (3,422) |
| Production | (3,781) | (12,615) |
| December 31, 2001 | 25,462 | 61,797 |
| Purchases of reserves in place | 223 | 57,728 |
| Extensions, discoveries and other additions | 2,117 | 32,492 |
| Revisions | 1,525 | (5,295) |
| Production | (2,974) | (19,765) |
| December 31, 2002 | 26,353 | 126,957 |
| Purchases of reserves in place | — | — |
| Extensions, discoveries and other additions | 2,275 | 40,270 |
| Revisions | 1,698 | (4,135) |
| Production | (2,913) | (28,688) |
| December 31, 2003 | 27,414 | 134,404 |
| Proved-developed reserves: | | |
| December 31, 2001 | 22,176 | 38,099 |
| December 31, 2002 | 21,070 | 70,014 |
| December 31, 2003 | 22,306 | 71,531 |

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

| | 2003 | 2002 |
|---|---|---|
| | (In thousands) | |
| Proved properties | $ 584,741 | $ 458,610 |
| Unproved properties | 8,716 | 9,180 |
| Accumulated depreciation, depletion and amortization | (207,237) | (118,976) |
| Net capitalized costs | $ 386,220 | $ 348,814 |

Costs incurred for oil and natural gas property acquisition, exploration and development activities for the years ended December 31, 2003, 2002 and 2001 are as follows:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | | (In thousands) | |
| Business combinations | | | |
| Proved properties | $ 850 | $116,415 | $ 523 |
| Unproved properties | — | 7,616 | — |
| Total business combinations | 850 | 124,031 | 523 |
| Lease acquisitions | 6,030 | 1,922 | 1,993 |
| Exploration | 60,170 | 27,083 | 45,592 |
| Development | 45,682 | 39,061 | 55,882 |
| Total finding and development costs | 111,882 | 68,066 | 103,467 |
| Total finding, development and acquisition costs | 112,732 | 192,097 | 103,990 |
| Asset retirement liabilities incurred | 812 | — | — |
| Asset retirement revisions | 2,519 | — | — |
| Costs incurred | $116,063 | $192,097 | $103,990 |

**Standardized Measure of Discounted Future Net Cash Flows Relating to Reserves**

The following information has been developed utilizing procedures prescribed by Statement of Financial Accounting Standards No. 69 (Statement 69), "Disclosures about Oil and Gas Producing Activities". It may be useful for certain comparative purposes, but should not be solely relied upon in evaluating the Company or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account in reviewing the following information: (1) future costs and selling prices will probably differ from those required to be used in these calculations; (2) due to future market conditions and governmental regulations, actual rates of production achieved in future years may vary significantly from the rate of production assumed in the calculations; (3) selection of a 10% discount rate is arbitrary and may not be reasonable as a measure of the relative risk inherent in realizing future net oil and gas revenues; and (4) future net revenues may be subject to different rates of income taxation.

Under the Standardized Measure, future cash inflows were estimated by applying period end oil and gas prices adjusted for field and determinable escalations to the estimated future production of period-end proved reserves. Future cash inflows were reduced by estimated future development, abandonment and production costs based on period-end costs in order to arrive at net cash flow before tax. Future income tax expense has been computed by applying period-end statutory tax rates to aggregate future net cash flows, reduced by the tax basis of the properties involved and tax carryforwards. Use of a 10% discount rate is required by Statement 69.

Management does not rely solely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

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

| | 2003 | 2002 | 2001 |
|---|---|---|---|
| | | (In thousands) | |
| Future cash inflows | $1,672,895 | $1,392,062 | $ 630,941 |
| Future production costs | (441,042) | (355,131) | (293,945) |
| Future development and abandonment costs | (264,404) | (220,946) | (168,989) |
| Future income tax expense | (245,934) | (183,377) | (4,688) |
| Future net cash flows after income taxes | 721,515 | 632,608 | 163,319 |
| 10% annual discount for estimated timing of cash flows | 192,100 | 155,707 | (39,942) |
| Standardized measure of discounted future net cash flows | $ 529,415 | $ 476,901 | $ 123,377 |

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved oil and natural gas reserves for the years ended December 31, 2003, 2002 and 2001 is as follows:

| | 2003 | 2002 | 2001 |
|---|---|---|---|
| | | (In thousands) | |
| Beginning of the period | $ 476,901 | $ 123,377 | $ 348,102 |
| Sales and transfers of oil and natural gas produced, net of production costs | (185,360) | (93,174) | (100,411) |
| Net changes in prices and production costs | 59,988 | 247,642 | (349,126) |
| Extensions, discoveries and improved recoveries, net of future production costs | 149,459 | 131,796 | 49,217 |
| Revision of quantity estimates | 18,380 | 9,927 | (12,619) |
| Previously estimated development costs incurred during the period | 21,379 | 32,189 | 10,861 |
| Purchase and sales of reserves in place | — | 179,772 | 637 |
| Changes in estimated future development costs | (15,851) | (19,403) | (20,014) |
| Changes in production rates (timing) and other | (37,680) | (22,510) | 11,638 |
| Accretion of discount | 60,827 | 12,912 | 48,995 |
| Net change in income taxes | (18,628) | (125,627) | 136,097 |
| Net (decrease) increase | 52,514 | 353,524 | (224,725) |
| End of period | $ 529,415 | $ 476,901 | $ 123,377 |

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2003 was based on period-end prices of $6.15 per Mcf for natural gas and $30.88 per barrel for crude oil. The December 31, 2002 computation was based on period-end prices of $4.83 per Mcf for natural gas and $29.53 per barrel for crude oil. The December 31, 2001 computation was based on period-end prices of $2.71 per Mcf for natural gas and $18.21 per barrel for crude oil. Spot prices as of February 25, 2004 were $5.08 per Mmbtu for natural gas and $32.50 per barrel for crude oil before adjustment for lease quality, transportation fees and price differentials.

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

None.

**Item 9A.** ***Controls and Procedures***

Under the supervision and with the participation of certain members of our management, including the Chief Executive Officer and Chief Financial Officer, we completed an evaluation of the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended). Based on this evaluation, our Chief Executive Officer and Chief Financial Officer believe that the disclosure controls and procedures were effective as of the end of the period covered by this report with respect to timely communication to them and other members of management responsible for preparing periodic reports and all material information required to be disclosed in this report as it relates to our Company and its consolidated subsidiaries. In October 2003, we implemented a new accounting system that contains general ledger, payables and receivables, fixed assets and other related accounting functions. Certain new accounting processes and procedures were implemented at that time to support the new software. This system change is the result of our process to evaluate and upgrade or replace systems and related processes to support our evolving operational needs. During the period from implementation through December 31, 2003, the new system and supporting processes were used to record and report our financial results, which are included in our consolidated totals. Following evaluation, management believes that the new system has been successfully implemented. Except for the new accounting system, there was no change in our internal control over financial reporting during the quarter ended December 31, 2003 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Our management, including the Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures or our internal controls will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons or by collusion of two or more people. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. Accordingly, our disclosure controls and procedures are designed to provide reasonable, not absolute, assurance that the objectives of our disclosure control system are met and, as set forth above, our Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period, that our disclosure controls and procedures were sufficiently effective to provide reasonable assurance that the objectives of our disclosure control system were met.

## PART III

**Item 10.** ***Directors and Executive Officers of the Registrant***

Except as set forth below, for information required by Item 10 regarding our directors and executive officers, see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on May 13, 2004, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference, and "Part I — Item 4A. Executive Officers".

Code of Ethics — The Company has adopted a code of ethics that applies to all directors and employees, including our chief executive officer, chief financial officer and controller. Prior to the time of our 2004 Annual

Meeting of Stockholders the code of ethics will be posted on our website at *www.eplweb.com.* A copy is also available by writing to the Secretary of the Company at 210 St. Charles Avenue, Suite 3400, New Orleans, Louisiana, 70170. The Company will post on its website any waiver the Code of Conduct granted to any of its directors or executive officers.

### Item 11. *Executive Compensation*

For information required by Item 11 see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on May 13, 2004, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

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

Except as set forth below, for the information required by Item 12 see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on May 13, 2004, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

**Securities Authorized for Issuance Under Equity Compensation Plans**

The following table provides information as of December 31, 2003, with respect to compensation plans under which our equity securities are authorized for issuance.

| | Number of Securities to be Issued upon Exercise of Outstanding Options | Weighted Average Exercise Price of Outstanding Options | Number of Securities Remaining Available for Future Grant |
|---|---|---|---|
| Equity compensation plans approved by stockholders | 2,009,282 | $9.68 | 2,584,978 |
| Equity compensation plans not approved by stockholders | — | — | — |

See note 15 to our consolidated financial statements for further information regarding the significant features of the above plans.

### Item 13. *Certain Relationships and Related Transactions*

For information required by Item 13 see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on May 13, 2004, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

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

For information required by Item 14 see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on May 13, 2004, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

## PART IV

**Item 15.** ***Exhibits, Financial Statement Schedules, and Reports on Form 8-K***

1. *Financial Statements:*

The following financial statements are included in Part II of this Report:

Independent Auditor's Report

Consolidated Balance Sheets as of December 31, 2003 and 2002

Consolidated Statements of Operations for the years ended December 31, 2003, 2002 and 2001

Consolidated Statements of Changes in Stockholders' Equity for the years ended December 31, 2003, 2002 and 2001

Consolidated Statements of Cash Flows for the years ended December 31, 2003, 2002 and 2001

Notes to the Consolidated Financial Statements

2. *Reports on Form 8-K*

On November 12, 2003 the Company filed a current report on Form 8-K, reporting, under Items 5 and 7, the agreement of Evercore Capital Partners, L.P. and certain of its affiliates to sell 4,544,572 shares of the Company's common stock and enclosing the underwriting agreement dated November 10, 2003.

3. *Exhibits*

| Exhibit Number | Title |
|---|---|
| 3.1 | — Restated Certificate of Incorporation of Energy Partners, Ltd., dated as of November 16, 1999 (incorporated by reference to Exhibit 3.1 to EPL's registration statement on Form S-1 (File No. 333-42876)). |
| 3.2 | — Amendment to Restated Certificate of Incorporation of Energy Partners, Ltd., dated as of September 15, 2000 (incorporated by reference to Exhibit 3.2 to EPL's registration statement on Form S-1 (File No. 333-42876)). |
| 3.3 | — Certificate of Elimination of the Series A Convertible Preferred Stock, Series B Convertible Preferred Stock and Series C Preferred Stock of Energy Partners, Ltd. (incorporated by reference to Exhibit 4.2 of EPL's Form 8-K filed January 22, 2002). |
| 3.4 | — Certificate of Designation of the Series D Exchangeable Convertible Preferred Stock of Energy Partners, Ltd. (incorporated by reference to Exhibit 4.3 of EPL's Form 8-K filed January 22, 2002). |
| 3.5 | — Amended and Restated Bylaws of Energy Partners, Ltd., dated as of March 20, 2003 (incorporated by reference to Exhibit 3.1 to EPL's current report on Form 8-K filed April 3, 2003 (File No. 333-42876)). |
| 4.1 | — Registration Rights Agreement by and between Energy Partners, Ltd., Evercore Capital Partners L.P., Evercore Capital Partners (NQ) L.P., Evercore Capital Offshore Partners L.P., Energy Income Fund, L.P. and the Individual Shareholders of the Company signatories thereto dated as of November 17, 1999 (incorporated by reference to Exhibit 4.5 to EPL's registration statement on Form S-1 (File No. 333-42876)). |
| 4.2 | — Amendment One to the Registration Rights Agreement between Energy Partners, Ltd., and Evercore Capital Partners L.P., Evercore Capital Partners (NQ) L.P., Evercore Capital Offshore Partners L.P., Energy Income Fund, L.P. and certain Individual Shareholders of the Company Effective November 3, 2003 (incorporated by reference in Exhibit 10.1 to EPL's Form 10-K filed November 12, 2003 (File No. 001-16179). |
| 10.1 | — Amended and Restated 2000 Long Term Stock Incentive Plan (incorporated by reference to EPL's proxy statement on Form 14A filed March 27, 2002 (File No. 001-16179)). |
| 10.2 | — 2000 Stock Option Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.26 to EPL's registration statement on Form S-1 (File No. 333-42876)). |

| Exhibit Number | Title |
|---|---|
| 10.3 | — First Amendment to 2000 Stock Option Plan for Non-Employee Directors. (incorporated by reference to Exhibit 10.4 to EPL's Form 10-K filed March 15, 2002 (File No. 001-16179)). |
| 10.4* | — Amended and Restated Stock and Deferral Plan for Non-Employee Directors. |
| 10.5 | — Employment and Stock Ownership Agreement by and between Energy Partners, Ltd. and Gary L. Hall (incorporated by reference to Exhibit 10.2 of EPL's Form 8-K filed January 22, 2002). |
| 10.6 | — Employment and Stock Ownership Agreement by and between Energy Partners, Ltd. and John H. Peper (incorporated by reference to Exhibit 10.3 of EPL's Form 8-K filed January 22, 2002). |
| 10.7 | — Employment and Stock Ownership Agreement by and between Energy Partners, Ltd. and Bruce R. Sidner (incorporated by reference to Exhibit 10.4 of EPL's Form 8-K filed January 22, 2002). |
| 10.8 | — First Amendment to the Third Amended and Restated Revolving Credit Agreement, among Energy Partners, Ltd., EPL of Louisiana, L.L.C. and Delaware EPL of Texas, LLC, the undersigned banks and financial institutions that are parties to the Credit Agreement and Bank One, N.A., dated as of July 28, 2003 (incorporated by reference to Exhibit 10.1 of EPL's Form 10-Q filed August 8, 2003). |
| 10.9 | — Purchase and Sale Agreement by and between Ocean Energy, Inc. and Energy Partners, Ltd. dated as of January 26, 2000 (incorporated by reference to Exhibit 10.18, to EPL's registration statement on Form S-1 (File No. 333-42876)). |
| 10.10 | — Earnout Agreement dated as of January 15, 2002, by and between Energy Partners, Ltd. and Hall-Houston Oil Company (incorporated by reference to Exhibit 2.5 of EPL's Form 8-K filed January 22, 2002). |
| 10.11 | — First Amendment to Earnout Agreement between Energy Partners, Ltd. and Participants effective July 1, 2002 (incorporated by reference to Exhibit 10.1 to EPL's Form 10-Q filed November 13, 2002). |
| 10.12* | — Second Amendment to Earnout Agreement between Energy Partners, Ltd. and Participants effective January 1, 2003. |
| 21.1* | — Subsidiaries of Energy Partners, Ltd. |
| 23.1* | — Consent of KPMG LLP. |
| 23.2* | — Consent of Netherland, Sewell & Associates, Inc. |
| 23.3* | — Consent of Ryder Scott Company, L.P. |
| 31.1* | — Rule 13a-14a(a)/15d-14(a) Certification of Chairman, President, And Chief Executive Officer of Energy Partners, Ltd. |
| 31.2* | — Rule 13a-14a(a)/15d-14(a) Certification of Executive Vice President and Chief Financial Officer of Energy Partners, Ltd. |
| 32.0* | — Section 1350 Certifications |
| 99.1* | — Report of Independent Petroleum Engineers dated as of February 4, 2004. |
| 99.2* | — Report of Independent Petroleum Engineers dated as of February 9, 2004. |

* Filed herewith

## SIGNATURES

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

ENERGY PARTNERS, LTD.

By: /s/ RICHARD A. BACHMANN

Richard A. Bachmann
*Chairman, President*
*and Chief Executive Officer*

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

| Signature | Title | Date |
|---|---|---|
| /s/ RICHARD A. BACHMANN<br>Richard A. Bachmann | Chairman, President and Chief Executive Officer (Principal Executive Officer) | March 9, 2004 |
| /s/ SUZANNE V. BAER<br>Suzanne V. Baer | Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer) | March 9, 2004 |
| /s/ JOHN C. BUMGARNER, JR.<br>John C. Bumgarner, Jr. | Director | March 9, 2004 |
| /s/ JERRY D. CARLISLE<br>Jerry D. Carlisle | Director | March 9, 2004 |
| /s/ HAROLD D. CARTER<br>Harold D. Carter | Director | March 9, 2004 |
| /s/ ENOCH L. DAWKINS<br>Enoch L. Dawkins | Director | March 9, 2004 |
| /s/ ROBERT D. GERSHEN<br>Robert D. Gershen | Director | March 9, 2004 |
| /s/ GARY L. HALL<br>Gary L. Hall | Director | March 9, 2004 |
| /s/ WILLIAM O. HILTZ<br>William O. Hiltz | Director | March 9, 2004 |
| /s/ EAMON M. KELLY<br>Eamon M. Kelly | Director | March 3, 2004 |
| /s/ JOHN G. PHILLIPS<br>John G. Phillips | Director | March 9, 2004 |

## BOARD OF DIRECTORS

**Richard A. Bachmann**
Founder, Chairman of the Board, President and Chief Executive Officer
Energy Partners, Ltd.

**John C. Bumgarner, Jr. (2)**
Managing Member
Utica Plaza, L.L.C.

**Jerry D. Carlisle (1)**
Adjunct Professor
University of New Orleans

**Harold D. Carter (1)**
Independent oil and natural gas consultant

**Enoch L. Dawkins (1)**
Retired President
Murphy Exploration and Production Company

**Robert D. Gershen (2) (3)**
President
Associated Energy Managers, L.L.C.

**Gary L. Hall**
Vice Chairman
Energy Partners, Ltd.

**William O. Hiltz (1)**
Senior Managing Director
Evercore Partners

**Dr. Eamon M. Kelly (1) (3)**
President Emeritus and Professor, Tulane University

**John G. Phillips (2) (3)**
Retired Chairman, President, and Chief Executive Officer
The Louisiana Land and Exploration Company

(1) Audit Committee
(2) Compensation Committee
(3) Nominating and Governance Committee

## OFFICERS

**Richard A. Bachmann**
Founder, Chairman of the Board, President, and Chief Executive Officer

**Gary L. Hall**
Vice Chairman of the Board

**Suzanne V. Baer**
Executive Vice President and Chief Financial Officer

**John H. Peper**
Executive Vice President, General Counsel, and Corporate Secretary

**Bruce R. Sidner**
Executive Vice President - Exploration

**T. Rodney Dykes**
Senior Vice President - Production

**William Flores, Jr.**
Senior Vice President - Drilling

**L. Keith Vincent**
Vice President - Land

**Louis E. Willhoit, Jr.**
Vice President - Geophysics

**Kenneth P. Smith**
Treasurer

## CORPORATE INFORMATION

Corporate Office
201 St. Charles Ave.
Suite 3400
New Orleans, LA 70170
504-569-1875
www.eplweb.com

Houston Office
700 Louisiana St., Suite 2100
Houston, TX 77002

Registrar and Transfer Agent
Mellon Investor Services
85 Challenger Road
Ridgefield Park, NJ 07660
800-635-9270
www.melloninvestor.com

Annual Meeting
The Annual Meeting of Stockholders will be held in New Orleans on Thursday, May 13, 2004.

Stock Exchange Listing
New York Stock Exchange
Symbol: EPL

Investor Information
Information on the Company, including this annual report and Form 10-K, news releases, latest analyst presentation and quarterly conference call recording are available on EPL's web site at www.eplweb.com. Interested parties may also contact the Company's investor relations representative at 504-569-1875.

## ABBREVIATIONS

| | |
|---|---|
| Bbl | Barrel |
| Boe | Barrels of oil equivalent* |
| Mbbls | Thousands of barrels |
| Mmboe | Millions of barrels of oil equivalent |
| Mcf | Thousand cubic feet |
| Mmcf | Million cubic feet |
| Shelf | Shallow waters of the outer continental shelf of the Gulf of Mexico |

* Converted on an energy equivalent ratio of 6 to 1.

EPL

ENERGY PARTNERS, LTD.

201 St. Charles Avenue
Suite 3400
New Orleans, Louisiana 70170
www.eplweb.com