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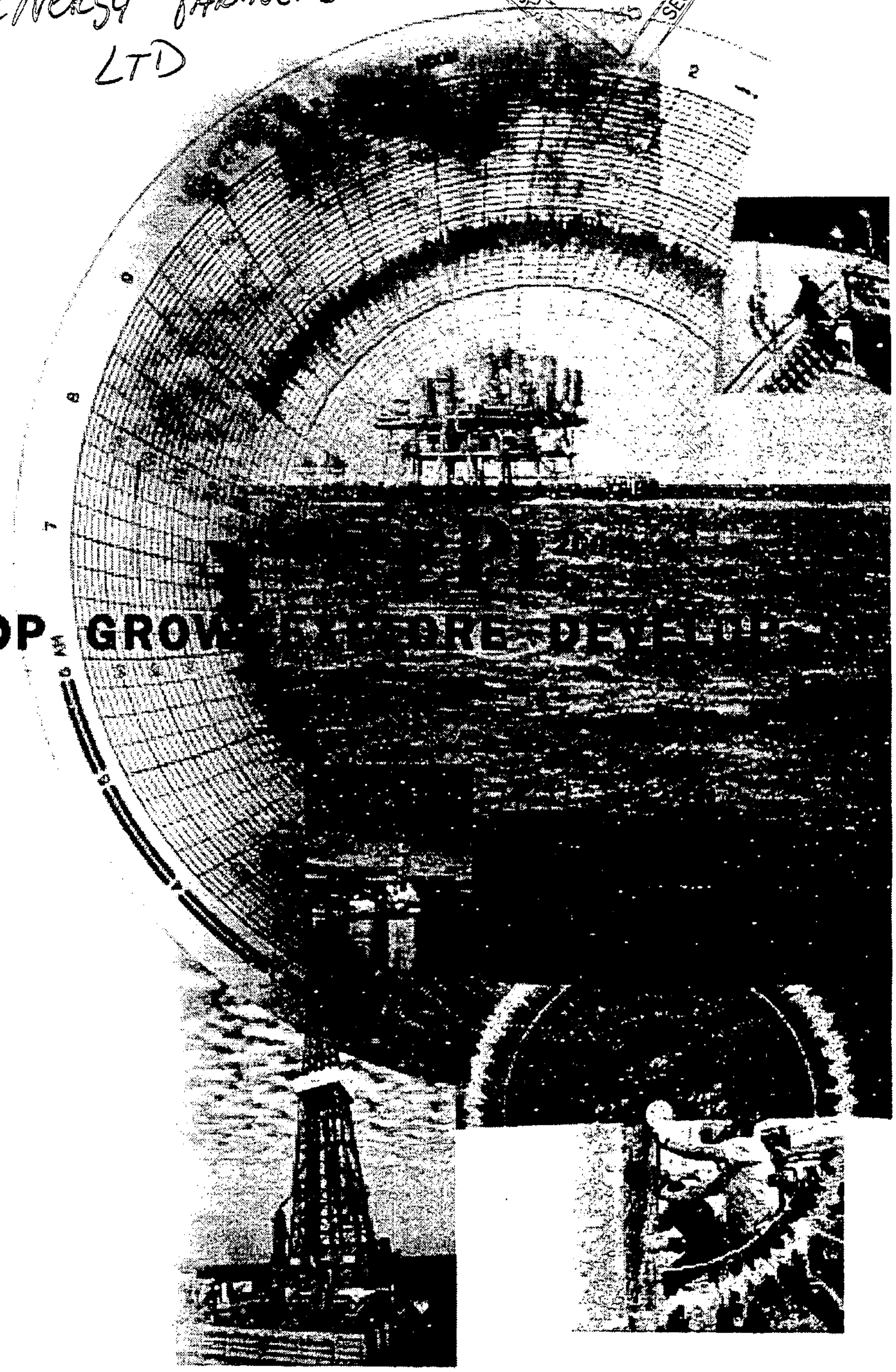
ENERGY PARTNERS
LTD





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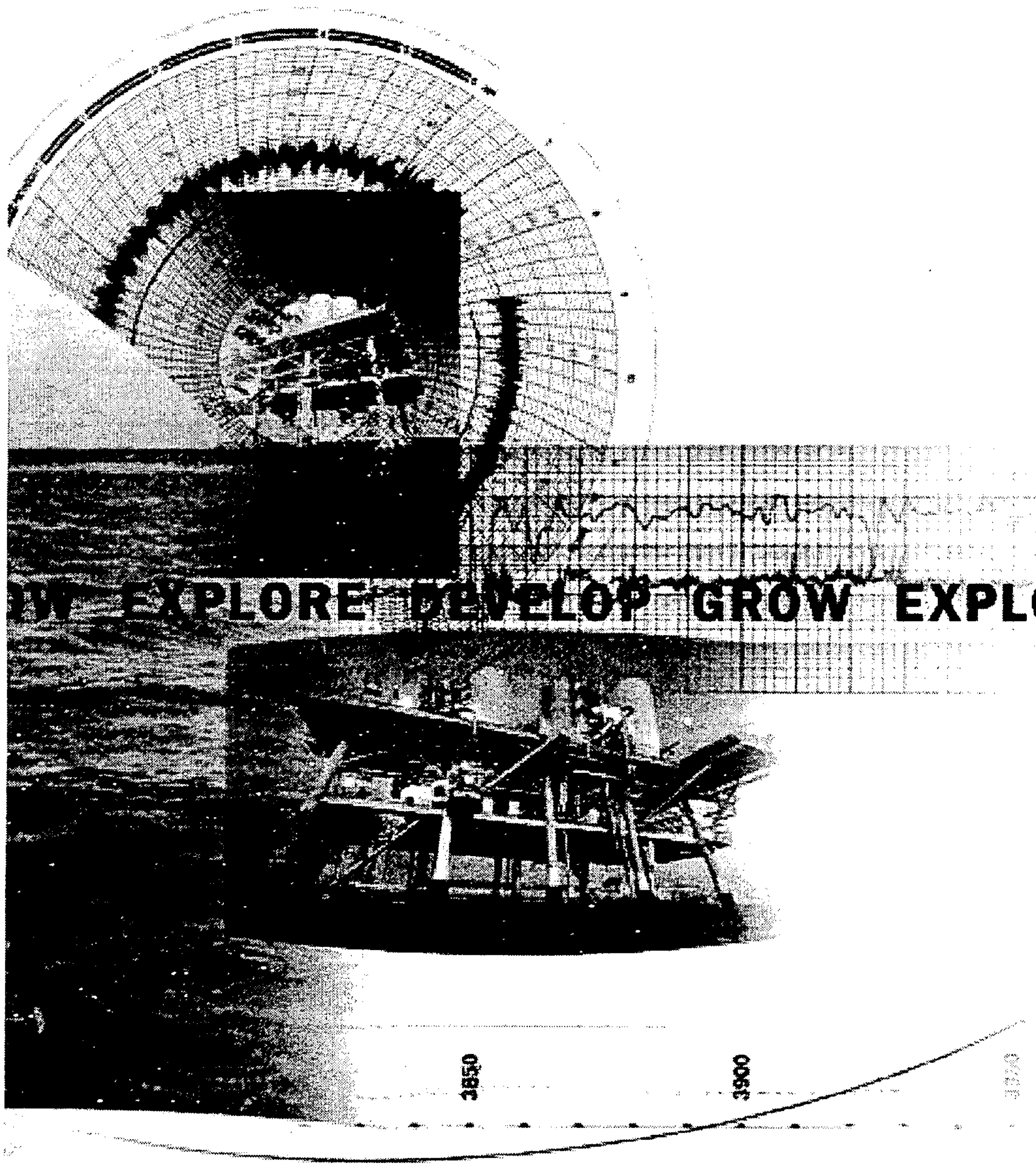
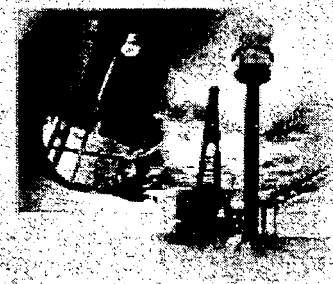


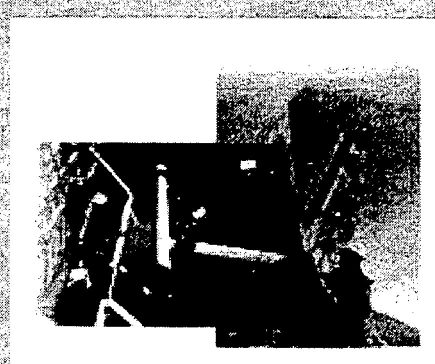

**OW EXPLORE DEVELOP GROW EXPLORE DEVELOP GR**



**Energy Partners, Ltd.** (EPL) is an independent oil and natural gas exploration and production company with operations focused along the U.S. Gulf Coast, both onshore in south Louisiana and offshore in the shallow to moderate depth waters of the Gulf of Mexico Shelf.

Since our inception in 1998, we have focused on a single goal: to create shareholder value through responsible growth. We have achieved that growth through a sustainable process that generates an extensive array of drilling opportunities and identifies strategic property acquisitions that can further enhance our prospect portfolio.

In 2004, our risk-balanced drilling program generated remarkable success that will yield sizable production growth for 2005. Also, late in 2004, we announced an acquisition that created a new core area for us in south Louisiana, a region where our technical staff already has a wealth of experience. This annual report will discuss the success of our strategy in 2004 and our plans for 2005 forward to explore, develop and grow.



## FINANCIAL DATA

| (In thousands, except price and per share amounts) | 2004 | 2003 | 2002 | 2001 | 2000 |
|---|---|---|---|---|---|
| Revenues | $ 295,210 | $ 230,187 | $ 133,788 | $ 146,240 | $ 111,017 |
| Income (loss) from operations (a) | 86,068 | 58,560 | (6,600) | 20,663 | (940) |
| Net income (loss) | 46,416 | 33,250 | (8,799) | 11,974 | (18,684) |
| Net income (loss) per diluted share (b) | $ 1.20 | $ 0.93 | $ (0.44) | $ 0.44 | $ (2.27) |
| Diluted weighted average common shares | 38,649 | 35,575 | 27,467 | 26,920 | 11,160 |
| Total finding and development costs (c) | 192,064 | 111,882 | 68,066 | 103,467 | 63,116 |
| Total assets | $ 647,678 | $ 544,181 | $ 384,220 | $ 242,777 | $ 208,149 |
| Long-term debt | 150,217 | 150,416 | 103,779 | 25,493 | 100 |
| Stockholders' equity | 315,049 | 261,485 | 191,922 | 164,867 | 150,591 |

## OPERATING DATA

| | 2004 | 2003 | 2002 | 2001 | 2000 |
|---|---|---|---|---|---|
| Total estimated net proved reserves: | | | | | |
| Oil (Mbbls) | 28,770 | 27,414 | 26,353 | 25,462 | 27,521 |
| Natural gas (Mmcf) | 149,835 | 134,404 | 126,957 | 61,797 | 49,150 |
| Total (Mboe) | 53,743 | 49,815 | 47,513 | 35,762 | 35,712 |
| Net production (per day): | | | | | |
| Oil (Bbls) | 8,663 | 7,978 | 8,148 | 10,358 | 7,622 |
| Natural gas (Mcf) | 82,098 | 78,596 | 54,150 | 34,562 | 15,781 |
| Total (Boe) | 22,346 | 21,077 | 17,173 | 16,118 | 10,252 |
| Average sales price:(d) | | | | | |
| Oil (per Bbl) | $ 35.01 | $ 28.02 | $ 23.64 | $ 23.44 | $ 25.86 |
| Natural gas (per Mcf) | 6.11 | 5.16 | 3.23 | 4.40 | 4.98 |
| Total (per Boe) | 36.01 | 29.86 | 21.40 | 24.50 | 26.89 |
| Present value of estimated future net revenues before income taxes (in thousands)(e) | $ 924,135 | $ 701,237 | $ 608,273 | $ 129,122 | $ 489,945 |
| Total well projects | 52 | 56 | 44 | 88 | 108 |
| Percentage of successful well projects | 79% | 82% | 77% | 86% | 91% |

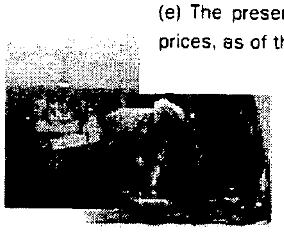
(a) The 2000 loss from operations includes a one time non-cash stock compensation charge for shares released from escrow to management and director stockholders of $38.2 million and non-cash charge of $2.1 million for bonus shares awarded to employees at the time of the initial public offering. The after-tax 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 income (loss) per diluted 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 of $6.7 million in 2000.

(c) Finding and development costs is computed by subtracting, from costs incurred, asset retirement amounts and business combinations of $5.7 million, $4.2 million, $124.0 million, $0.5 million and $119.9 million for the years ended December 31, 2004, 2003, 2002, 2001 and 2000, respectively.

(d) Net of the effect of hedging transactions.

(e) 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.



When we first detailed our goals for 2004, we estimated that production growth for 2004 would be 5% to 10% over 2003 levels. At mid-year, we felt that there was a good chance we might even exceed the high end of that range. In September, though, those plans were challenged by an event outside our control: Hurricane Ivan.

# EXPLORE DEVELOP GROW

As Hurricane Ivan approached the Gulf Coast, we took all appropriate measures to prepare for the storm, including shutting in all our production in the central and eastern Gulf of Mexico and evacuating our people. EPL was fortunate in that our facilities were spared a direct hit by the storm, but we still sustained some minor damage to facilities and pipelines. The response from our operations personnel in recovering from the storm and re-establishing production was outstanding, so the ultimate effect on us was minimal. Without the impact of Ivan and the lingering effects of damage to equipment and infrastructure in the Gulf, we believe production growth would have been close to 10% over 2003 levels.

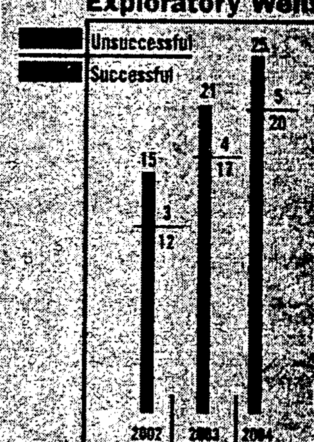
Other companies were not as fortunate as EPL, however, and Hurricane Ivan will be remembered as one of the most destructive storms to offshore infrastructure in memory.

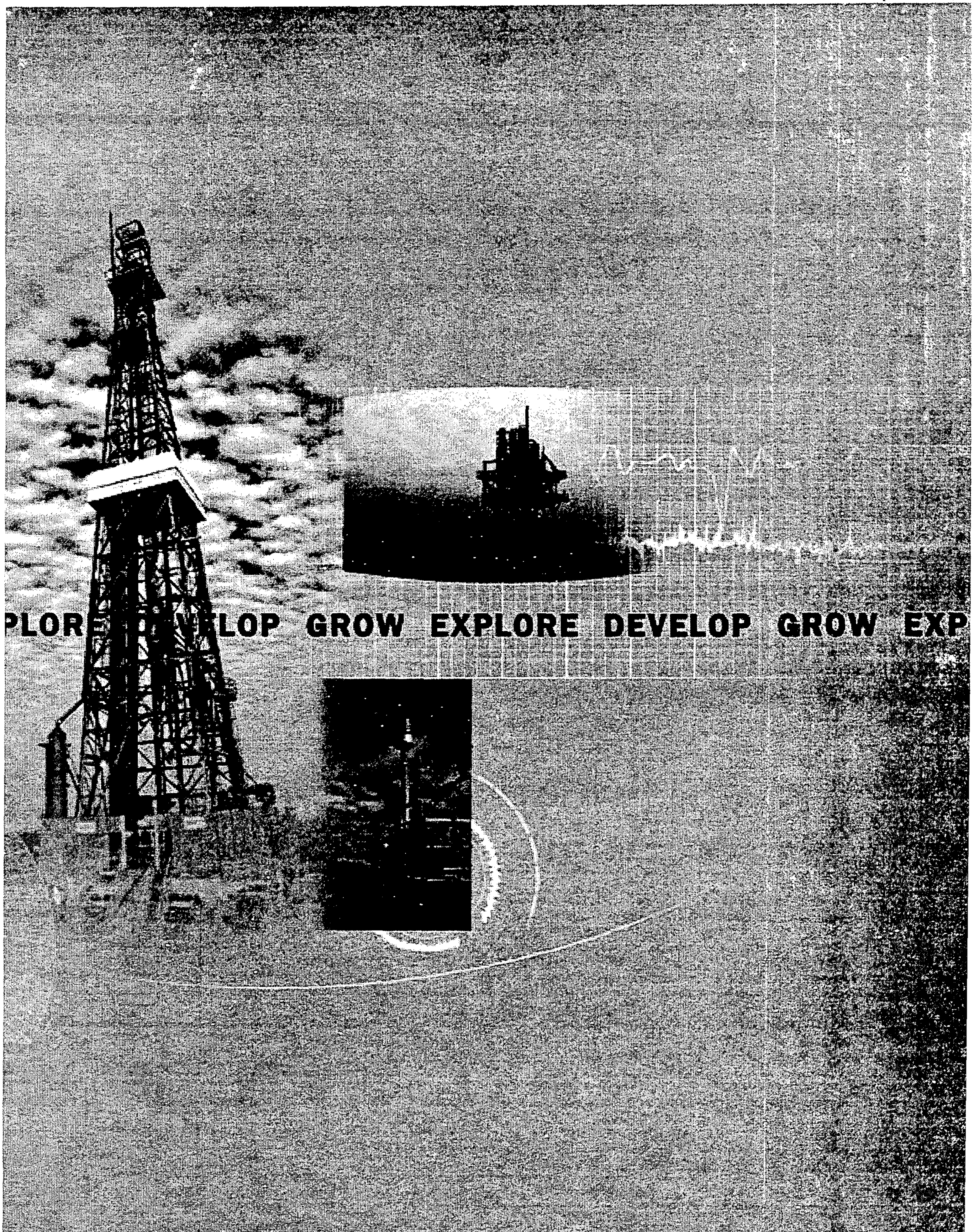
While EPL registered success in many areas in 2004, there are a few developments that I would like to discuss in more detail. The first of these is our continued success at South Timbalier 41.

We acquired South Timbalier 41 in the 2003 Central Gulf Lease Sale, and even though the block was adjacent to areas that had produced a tremendous amount of hydrocarbons, there had never been a well drilled on the block. We drilled the initial discovery well on the block in late 2003. We followed up that well with three more exploratory successes in 2004. Based on what we have found on the block to date, this field would qualify as a significant discovery for a company of any size, and we believe that there is significant upside potential remaining in the area. We plan to drill at least two more exploratory wells there in 2005 and are confident of continued success on the block. I think it is important to point out that our discovery at South Timbalier 41 stands as evidence of the regional expertise that we have cultivated here at EPL. While no company should expect finds like South Timbalier 41 year in and year out, we believe it is emblematic of the potential that remains on the Gulf of Mexico Shelf.

Another key development that came at the end of 2004 was our announcement of an acquisition bringing us into a

**Exploratory Wells**

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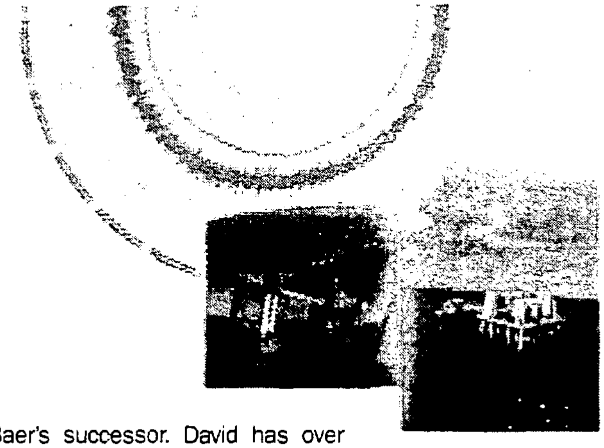


new core area, onshore south Louisiana. Since the acquisition did not close until January 2005, the effects are not reflected in our 2004 results. This new area will figure prominently in our 2005 results, as we plan to be very active here. Since south Louisiana is essentially an extension of our existing core area, the Gulf of Mexico, we have been able to immediately incorporate these new properties into our technical and production operations. Furthermore, the staff at EPL has a wealth of experience in the marshes of south Louisiana, so we are excited about what 2005 holds in store for this area.

2004 also saw us significantly strengthen the management team at EPL. In December Phillip Gobe joined us as Chief Operating Officer. He was most recently with Nuevo Energy until its sale to Plains Resources earlier in 2004, and prior to that he had been with Vastar Resources and ARCO. We consider ourselves fortunate to have him on board with us. His background in a variety of drilling and operational positions will make him a key element of our success going forward as we ramp up our level of activity.

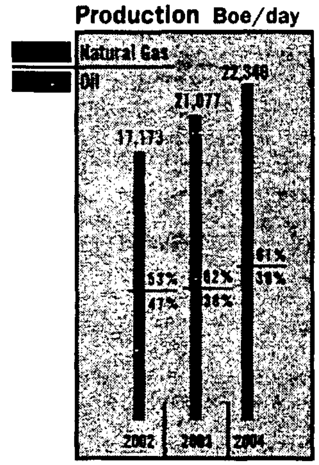
In early 2005, Suzanne Baer, our Chief Financial Officer since 2000, announced her retirement. I have worked with Suzanne for over 20 years, the last five of which were here at EPL. I would like to thank her for her hard work and invaluable contribution to building EPL into the Company it is today. Her personal and professional presence will be much missed, not just by me but all of us.

David Looney has recently joined us to be Ms. Baer's successor. David has over 25 years experience in various financial and energy-related capacities, and was most recently with EOG Resources, where he served as Vice President, Finance. We have great confidence in David in his new role as EPL's CFO, and we look forward to his contributions as we continue to grow and mature as a company.

As we look back on 2004, we are pleased with what we accomplished, but we are now focused on the work ahead. With the impressive goals we have set for 2005, we know there are also challenges, but we believe we have assembled the talent at EPL to meet those challenges. Our capital budget for 2005 is currently set at $240 million, and that level could well increase over the year. 2004 was a great year for EPL because of the hard work and dedication of all of our employees. It is our employees who contributed to the success of 2004, and it is our employees who will continue to make EPL a standout amongst its peers. We expect that 2005 will be even better as we continue to work at creating value for you, our shareholders.

Richard A. Bachmann
Chairman, President and CEO
March 15, 2005

**Production** Boe/day



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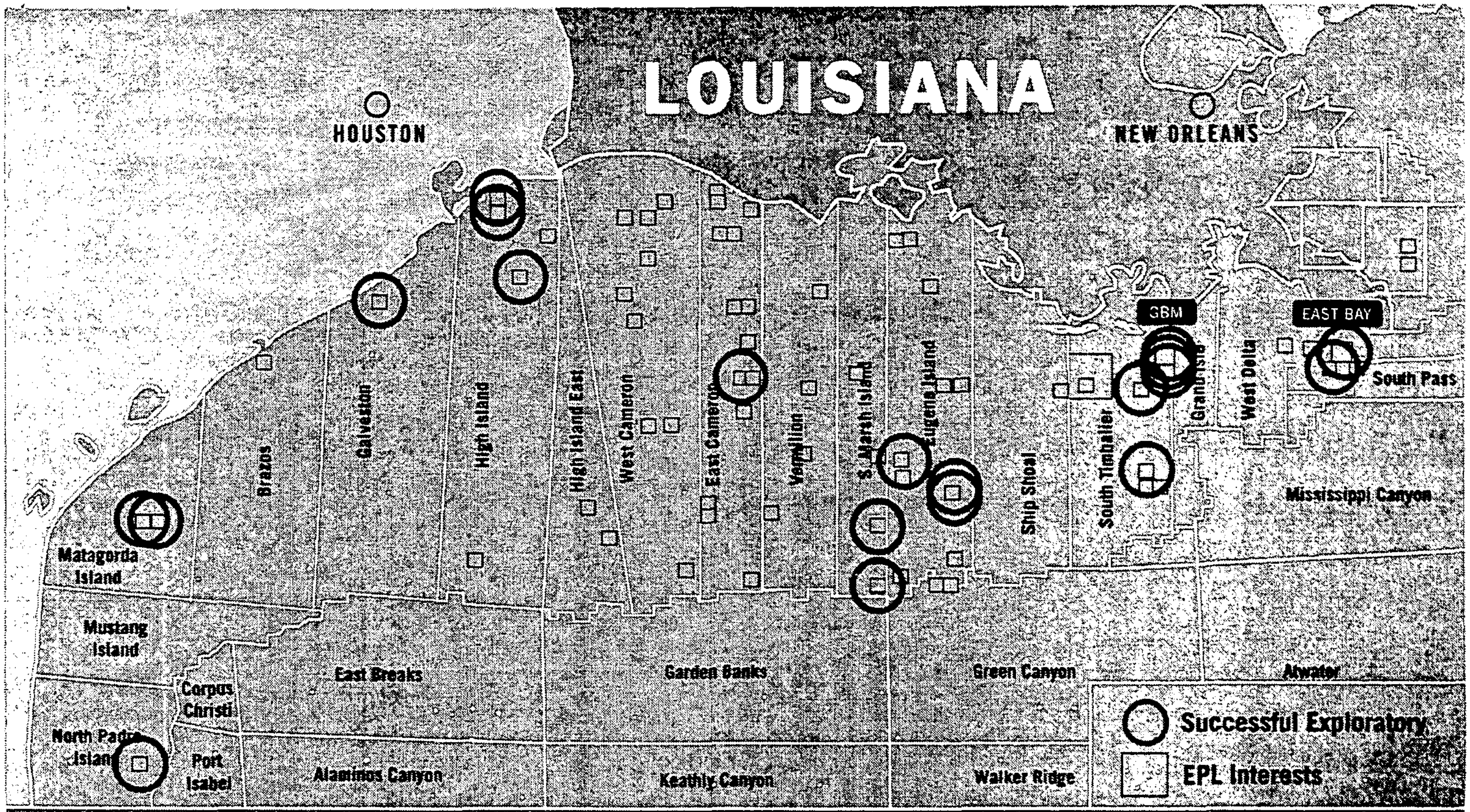
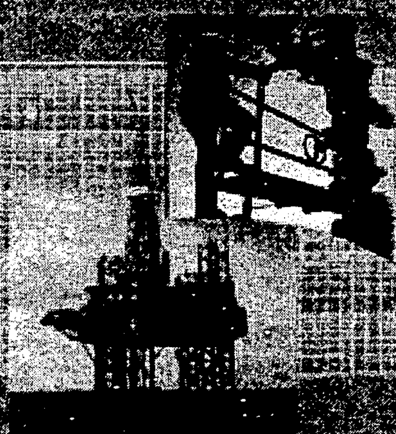
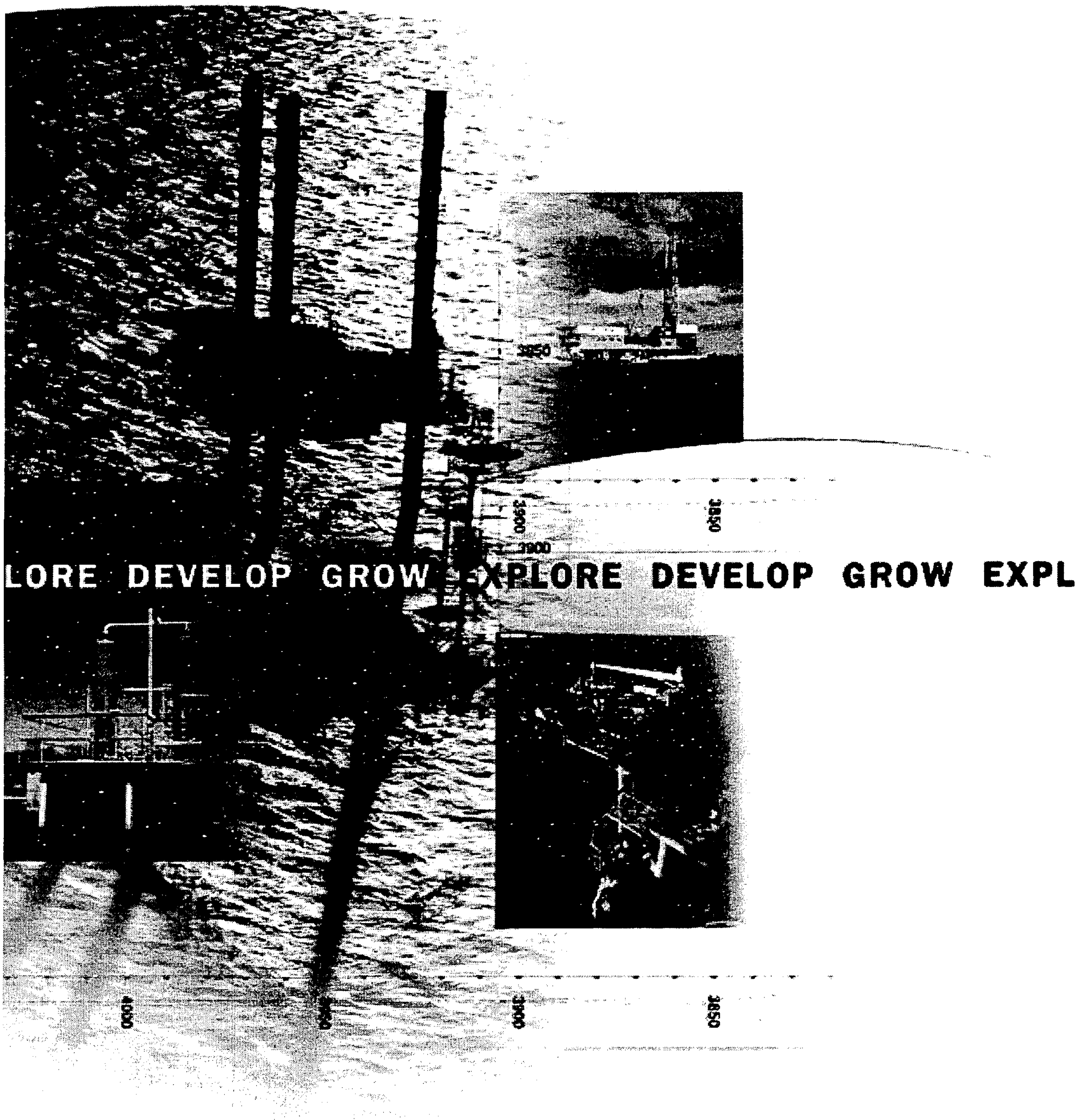



## SUSTAINABLE GROWTH



For the third consecutive year, EPL has grown its exploratory program and sustained an 80% plus success rate. In 2004 we drilled 25 exploratory wells and had 20 discoveries. The map above shows the locations of our 2004 exploratory successes and EPL's lease position on the Gulf of Mexico Shelf. EPL's exploratory activities span the Shelf, extending from North Padre Island in the west to the East Bay field in the east, near the mouth of the Mississippi River. Water depths of the exploratory tests range from [illegible] feet in the protected waters of south Louisiana to in excess of [illegible] feet near the Shelf edge.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3900
3850
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4000
3900
3850

# STRATEGIC REVIEW

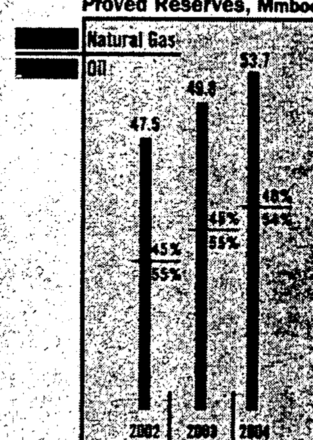
2004 was a year when we increased the scale of our operations while maintaining our historical track record of drilling success. The Company drilled a record 25 exploratory wells and registered 20 successes, continuing the success rate of approximately 80% that EPL has delivered since its inception in 1998. We also drilled six development wells, four of which were successes. On the development side, EPL successfully performed 17 workovers and recompletions in the year. We had a number of rig operations underway at all times and had as many as six rig operations underway at one point late in the year.

A key factor in our continuing growth has been our ability to quickly initiate production from new drilling successes. Eight of the 20 exploratory successes from 2004 were onstream by year-end, and two additional wells came online in the first week of January. Two more successes from 2004 are expected online in the first half of 2005, and the remaining eight are expected online by the end of the year.

Production for 2004 averaged 22,346 barrels of oil equivalent per day, a record high for the Company and an increase of 6% over 2003's production levels. All of the growth in production resulted from successful drilling activities, as there were no acquisitions of reserves during 2004. Approximately 39% of our 2004 production was oil and the remaining 61% was natural gas. During 2004 we operated approximately 85% of our production.

Our active exploration and development program resulted in reserve replacement of 176% through extensions, discoveries, and other additions. Including the impact of revisions to previous reserve estimates, the Company replaced 148% of 2004 production at a cost of $15.86. The acquisition of south Louisiana properties, which was announced in December 2004, closed in January 2005, therefore its impact is not included in year-end 2004 reserves. EPL's three-year average for all-in reserve replacement stands at 181% at an average cost of $12.36 per Boe. The three-year average for reserve replacement from drill bit additions and revisions stands at 137% at an average cost of $12.29 per Boe, and

**Proved Reserves, Mmboe**



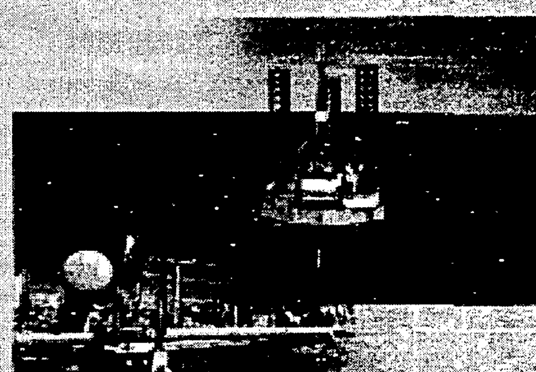
reserve replacement from acquisitions averaged 44% at a cost of $12.60 per Boe over the same period. Since inception, EPL has averaged 266% all-in annual reserve replacement at a cost of $9.57 per Boe. Drill bit and revisions replacements have averaged 138% at $12.74 per Boe, and acquisitions have averaged 129% at $6.08 per Boe.

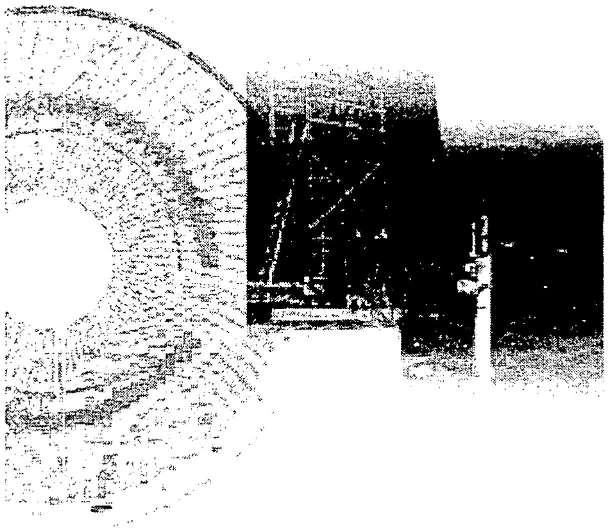
At year-end 2004, proved reserves stood at 53.7 million barrels of oil equivalent, up 8% from the prior year-end. 54% of our reserves were oil, and 46% were natural gas on a barrels of oil equivalent basis and 78% of the Company's reserves were classified as proved developed. All of EPL's reserves are engineered by our independent, third party engineers, Netherland, Sewell & Associates and Ryder Scott L.P. EPL's reserve life based on those year-end 2004 reserves was 6.6 years.

EPL again increased its lease position during 2004, resulting in a total of 308,000 gross acres held under lease at year-end. We incremented our lease position through several transactions, including trades with industry partners, and state and Federal lease sales. In the 2004 Central Gulf Lease Sale held by the Minerals Management Service, EPL was the successful high bidder on and was awarded leases on eight Outer Continental Shelf blocks representing approximately 35,000 gross acres. While we were only able to fit one of the prospects from this lease sale into our 2004 exploratory program, we have already drilled two prospects from the 2004 lease sale in 2005 and have plans to drill the remaining five by the end of the year. As of year-end 2004, we owned an interest in 327 productive wells.

We spent a total of $192.1 million in our exploration and development program in 2004. The majority of that, $113.3 million, was spent on exploratory activities, including seismic costs and the completion of successful exploratory wells. We also spent $72.2 million on development projects, including platforms and facilities, and spent $6.6 million on lease acquisitions. EPL maintained its historic risk-balanced profile in 2004, with the greatest portion of the exploratory budget allocated to moderate risk prospects. As the Company has grown, we have also judiciously increased our exposure to high potential projects. We will continue to evaluate the risk profile of the exploratory program to expose our shareholders to high potential projects without incurring undue risk.

One such high potential project for EPL has been South Timbalier 41. This block

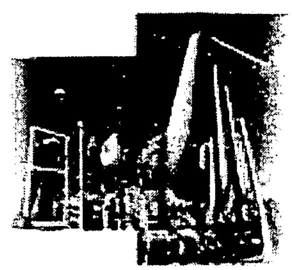




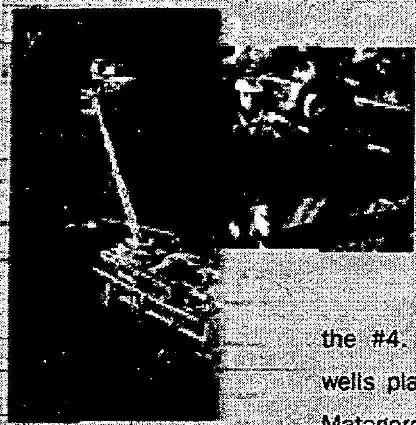
is located immediately south of South Timbalier 26, which was one of the first properties acquired by EPL. We acquired a 60% interest in South Timbalier 41 in the 2003 Central Gulf Lease Sale and drilled the initial discovery well on the block just before the close of 2003. It was placed on production in early 2004 using existing infrastructure on South Timbalier 26. In 2004, we drilled three follow-up exploratory wells on the block and logged three more successes. The first of the three successes in 2004 was the #2 well, now known as the #B-1 well. The second success in 2004 was the #A-2 well, and the third was the #4 well.

After the success with the #2 well, EPL installed the "B" platform at the site and contracted for a mobile offshore production unit (MOPU) to accelerate the start up of production from the well. The MOPU, which has the capacity to process up to 100 Mmcf of natural gas per day, is pictured on page eight of this report. While arrangements were being made to bring the MOPU into the field, EPL logged its second exploratory success of the year on the block with the #A-2 well. The MOPU arrived on site in November of 2004, and production from the #B-1 and #A-2 wells started in January, too late to contribute for 2004 but giving us an early start on our planned production ramp up in 2005.

The South Timbalier 41 #4 well was the third exploratory success on the block in 2004, and it was also the last well we drilled in the year. The #4 well, soon to be known as the #C-1 well, will also be produced through the MOPU. To date, we have found eleven productive sands on the block between the four wells. The South Timbalier 41 #3 well is a well that will be drilled early in 2005 to test a separate fault block on South Timbalier 41. We expect to drill at least one more exploratory well on the block before the end of the year. EPL is in the process of designing permanent facilities for the block, which we plan to have in the field by the end of the year. By any measure, this new field discovery has been an exciting exploratory project for the Company, and ranks as the largest discovery in our history. We believe there remains additional upside on the block yet to test. Our success at South Timbalier 41 is an excellent example of how EPL uses the regional knowledge it has developed in-house to pursue exploratory opportunities in what many believed to be a mature area.



EPL also drilled other key exploratory wells during 2004 in a number of locations across the Gulf of Mexico. At Eugene Island 277, we drilled two successful exploratory wells, the #A-3 sidetrack and



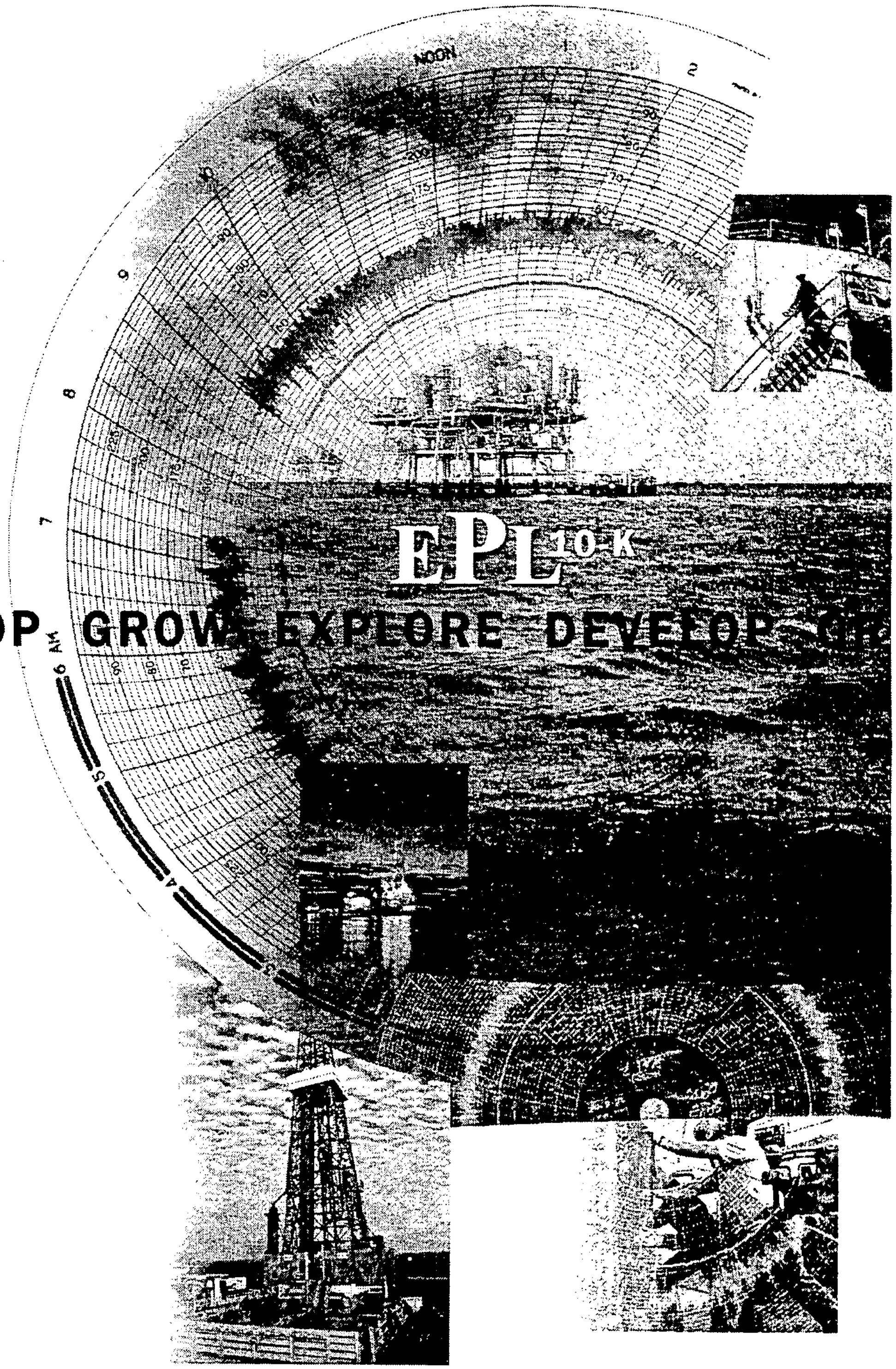
EXPLORE DEVELOP GROW

the #4. We have two more exploratory wells planned on this block in 2005. At Matagorda Island 639 and 640, we drilled two successful exploratory wells, one on each block, from the same surface location. We plan to install a support structure there in the first half of 2005 and expect initial production early in the second half of the year. Around mid-year 2004, we had our first exploratory success on South Timbalier 46, and we have at least one more exploratory well on the block planned for 2005. At South Marsh Island 109, we followed up our three exploratory successes in 2003 with the successful #A-4 well in 2004. Just after the close of 2004, we drilled our fifth successful exploratory well on the block, the #A-5. At South Marsh Island 192, we participated in a discovery with the #A-2 well, and the operator is drilling a follow-up development well, the #A-3. We also had two significant single well discoveries at North Padre Island 913 and Galveston 227.

At East Bay, EPL drilled two successful exploratory wells and completed the integration and reprocessing of all of our seismic data in the area. We have developed a number of new moderate and high potential prospects as a result of the new data.

Near the end of 2004, we added a new core area of operations when we announced the acquisition of a group of prospects, acreage and reserves in south Louisiana from Castex for $146 million. The acquisition did not close until January 2005, so it was not included in our results for the year, but was a major accomplishment negotiated in 2004. We bought the package because we believe south Louisiana is an excellent fit with our existing competencies and offshore core area. We also believe that the staff at EPL will bring unique value to the deal through our extensive experience in working south Louisiana properties. As part of the acquisition, we formed an Area of Mutual Interest with Castex covering over one million acres where we will each generate prospects. EPL and Castex will have the right of first refusal to participate in each other's prospects, and we expect this element of the acquisition to add considerable value. We have already drilled a number of successful wells on our new south Louisiana acreage, and we are planning for a minimum of 22 exploratory wells in the area in 2005.

EPL will increase its activity offshore in 2005 as well, with a minimum of 30 wells planned. The initial exploration and development budget supporting our increased onshore and offshore activity is $240 million, which represents a 26% increase from last year's revised budget of $190 million. This year's budget could increase significantly during the year if commodity prices remain in their current ranges.

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# 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, 2004**

**or**

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

**For the transition period from to**

**Commission file number: 001-16179**

# Energy Partners, Ltd.

*(Exact name of registrant as specified in its charter)*

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

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

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

| Title of Each Class | Name of Exchange on Which Registered |
|---|---|
| Common Stock, Par Value $0.01 Per Share | New York Stock Exchange |

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

Indicate by 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, 2004 based on the closing price of such stock as quoted on the New York Stock Exchange on that date was $411,966,974.

As of February 25, 2005 there were 35,884,066 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 2005 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. Since our inception in 1998 we have focused on the shallow to moderate depth waters of the Gulf of Mexico Shelf. With the acquisition of south Louisiana properties in January 2005, discussed below, we have expanded our focus area to include the onshore Gulf Coast, which is similar geologically to the Gulf of Mexico Shelf. We concentrate on this 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, 2004, we had estimated proved reserves of approximately 149.8 Bcf of natural gas and 28.8 Mmbbls of oil, or an aggregate of approximately 53.7 Mmboe, with a present value of estimated pre-tax future net cash flows of $924.1 million, and a standardized measure of discounted future net cash flows of $667.7 million.

Since our incorporation in January 1998 by Richard A. Bachmann, 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. As we have grown, we have strengthened our management team, expanded our property base, reduced our geographic concentration, and moved to a more balanced oil and natural gas reserves and production profile. We have also expanded our technical knowledge base through the addition of high quality personnel and geophysical and geological data.

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, our website contains our Corporate Governance Guidelines and the charters for our Audit, Compensation and Nominating Committees. Copies of such information are also available by writing to The Secretary of the Company at 201 St. Charles Avenue, Suite 3400, New Orleans, Louisiana 70170. Our web site and the information contained in it and connected to it shall not be deemed incorporated by reference into this Report on Form 10-K.

### *Acquisition of South Louisiana Reserves and Prospects*

On January 20, 2005, we closed the acquisition of properties and reserves onshore in south Louisiana from Castex Energy 1995, L.P. and Castex Energy, Inc. ("Castex") for $146.0 million in cash, after adjustments for the exercise of preferential rights by third parties and preliminary closing adjustments. The properties acquired include nine fields, four of which were producing at the time of the closing through 14 wells, with estimated proved reserves of 51.2 Bcfe. Also included were interests in 22 exploratory prospects scheduled to be drilled in 2005. Concurrent with the closing, our bank credit facility borrowing base was increased to $150 million, of which $60 million was drawn to fund the acquisition.

This acquisition has taken us into onshore south Louisiana, where our staff has a wealth of experience. In connection with the acquisition, we also entered into a two-year agreement with the seller of the properties that defines an area of mutual interest ("AMI") encompassing over one million acres in which we intend to jointly explore and develop oil and gas reserves over the next two years. Both the proved reserves acquired from the seller and the AMI are in the southern portions of Terrebone, Lafourche and Jefferson Parishes in Louisiana.

### *Exploration and Development Expenditures*

Our exploration and development expenditures for 2004 totaled $194.2 million inclusive of a $2.2 million contingent consideration payment to former HHOC stockholders resulting from the January 2002 acquisition of HHOC. For 2005, we have budgeted exploration and development expenditures of $240 million. This budget includes exploration and development activities on the newly acquired properties in south Louisiana as well as exploration and development activities on our offshore properties. The drilling portfolio, both onshore and offshore, includes a mixture of lower risk development and exploitation wells, moderate risk exploration opportunities and higher risk, higher potential exploration projects. Our 2005 budget does not include any acquisitions of proved reserves that may occur during the year, including the acquisitions of properties and reserves to date in 2005.

## Our Properties

At December 31, 2004, we had interests in 29 producing fields, 5 fields under development and one field on which drilling operations were then being conducted, 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 which extends from areas offshore central and western Louisiana to areas offshore Texas, is comprised of 21 producing fields. Over the last several years, we have continued to add to our leasehold acreage position in these areas through federal and state lease sales and trades with industry partners.

### 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 171 feet. East Bay encompasses nearly 48 square miles and is comprised primarily of the 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 all of these fields and own an average 96% interest in our acreage position with our working interest ranging from 18% to 100% and our net revenue interest varying up to a maximum of 86%. Inclusive of all lease acquisitions, our leasehold area covers 47,402 gross acres (45,499 net acres).

Our Eastern area operations accounted for approximately 33% of our net daily production and 15% ($28.2 million) of our capital expenditures during 2004.

## Central Area

Our Central area is located approximately 60 miles south of New Orleans in water depths of 168 feet or less and encompasses nearly 100 square miles. The focus of our central area operations is the Greater Bay Marchand area. Our key assets in this area include the South Timbalier 26 and 41 and Bay Marchand fields as well as currently undeveloped reserves in the South Timbalier 46 field.

In 2003, we drilled our initial discovery well in South Timbalier 41 on acreage acquired earlier that year in a federal lease sale. Three follow up wells have been drilled in the field, two of which were brought on production in early 2005. Development is currently under way for the third well and a fourth exploratory well is planned for early 2005. This field, in which additional reserve potential is yet to be tested, represents the most significant discovery in our history. In addition, through a series of transactions culminating in early 2000, as of December 31, 2004 we owned a 50% interest in the South Timbalier 26 field. We serve as operator of this field where we have interests in 12 producing wells.

On March 8, 2005, we closed the acquisition of the remaining 50% gross working interest in South Timbalier 26, above approximately 13,000 feet subsea that we did not already own from Apache Corporation for approximately $21.0 million after preliminary closing adjustments from the effective date of December 1, 2004. As a result of the acquisition, we now own a 100% gross working interest in this field. The acquisition expands our interest in our core Greater Bay Marchand area and gives us additional flexibility in undertaking the future development of the South Timbalier 26 field.

Our Central area operations accounted for approximately 27% of our net daily production and 32% ($61.5 million) of capital expenditures during 2004.

## Western Area

The properties in the Western area are located in water depths ranging from 20 to 476 feet with working interests ranging from 17% to 100%. We owned interests in 27 fields in this area at December 31, 2004, 21 of which were producing fields with another five under development and one on which drilling was then in progress.

Our Western area operations accounted for approximately 40% of our net daily production and 53% ($104.5 million) of our capital expenditures during 2004.

## 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, 2004, 2003 and 2002. The December 31, 2004, 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. 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, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| Total estimated net proved reserves(1): | | | |
| Oil (Mbbls) | 28,770 | 27,414 | 26,353 |
| Natural gas (Mmcf) | 149,835 | 134,404 | 126,957 |
| Total (Mboe) | 53,743 | 49,815 | 47,513 |
| Net proved developed reserves(2): | | | |
| Oil (Mbbls) | 24,737 | 22,306 | 21,070 |
| Natural gas (Mmcf) | 102,760 | 71,531 | 70,014 |
| Total (Mboe) | 41,864 | 34,228 | 32,739 |
| Estimated future net revenues before income taxes (in thousands)(3) | $1,271,083 | $967,449 | $815,985 |
| Present value of estimated future net revenues before income taxes (in thousands)(3)(4) | $ 924,135 | $701,237 | $608,273 |
| Standardized measure of discounted future net cash flows (in thousands)(5) | $ 667,668 | $529,415 | $476,901 |

(1) Approximately 69% of our total proved reserves were proved undeveloped and proved developed non-producing at December 31, 2004.

(2) Net proved developed non-producing reserves as of December 31, 2004 were 12,976 Mbbls and 72,073 Mmcf.

(3) The December 31, 2004 amount was calculated using a period-end oil price of $41.84 per barrel and a period-end natural gas price of $6.23 per Mcf, while 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 and the December 31, 2002 amount was calculated using a period-end oil price of $29.53 per barrel and a period-end price of $4.83 per Mcf.

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

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

### Costs Incurred in Oil and Natural Gas Activities

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| | | (In thousands) | |
| Business combinations: | | | |
| Proved properties | $ 2,166 | $ 850 | $116,415 |
| Unproved properties | — | — | 7,616 |
| Total business combinations | 2,166 | 850 | 124,031 |
| Lease acquisitions | 6,551 | 6,030 | 1,922 |
| Exploration | 113,278 | 60,170 | 27,083 |
| Development | 72,235 | 45,682 | 39,061 |
| Asset retirement liabilities incurred | 3,686 | 812 | — |
| Asset retirement revisions | (189) | 2,519 | — |
| Costs incurred | $197,727 | $116,063 | $192,097 |

### 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, 2004:

| | Total Productive Wells | |
|---|---|---|
| | Gross | Net |
| Oil | 252 | 221 |
| Natural gas | 75 | 54 |
| Total | 327 | 275 |

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

### Acreage

The following table sets forth information as of December 31, 2004 relating to acreage held by us. Developed acreage is assigned to producing wells.

| | Gross Acreage | Net Acreage |
|---|---|---|
| Developed: | | |
| Eastern area | 32,205 | 30,512 |
| Central area | 38,840 | 21,680 |
| Western area | 122,207 | 69,668 |
| Total | 193,252 | 121,860 |
| Undeveloped: | | |
| Eastern area | 15,197 | 15,197 |
| Central area | 2,552 | 2,310 |
| Western area | 96,682 | 91,028 |
| Total | 114,431 | 108,535 |

Leases covering 8% of our undeveloped net acreage will expire in 2005, approximately 28% in 2006, 15% in 2007, 11% in 2008, and 38% in 2009.

### Well Activity

The following table shows our well activity for the years ended December 31, 2004, 2003 and 2002. 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, | | | | | |
|---|---|---|---|---|---|---|
| | 2004 | | 2003 | | 2002 | |
| | Gross | Net | Gross | Net | Gross | Net |
| Development Wells: | | | | | | |
| Productive | 5.0 | 3.2 | 1.0 | 0.3 | 1.0 | 1.0 |
| Non-productive | 2.0 | 2.0 | 1.0 | 1.0 | — | — |
| Total | 7.0 | 5.2 | 2.0 | 1.3 | 1.0 | 1.0 |
| Exploration Wells: | | | | | | |
| Productive | 19.0 | 12.3 | 15.0 | 8.4 | 9.0 | 5.1 |
| Non-productive | 5.0 | 2.2 | 4.0 | 2.2 | 3.0 | 0.9 |
| Total | 24.0 | 14.5 | 19.0 | 10.6 | 12.0 | 6.0 |

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

### Title to Properties

Our properties are subject to customary royalty interests, liens under indebtedness, liens incident to operating agreements, mechanics and materialman liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interfere with the use of our properties in the operation of our business.

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

**Regulatory Matters**

***Regulation of Transportation and Sale of Natural Gas***

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, as amended ("NGA"), the Natural Gas Policy Act of 1978, as amended ("NGPA"), and regulations promulgated thereunder by the Federal Energy Regulatory Commission ("FERC") and its predecessors. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at 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 and a portion of South Timbalier 41 on the Gulf of Mexico OCS to Bayou Fourchon, Louisiana. Production transported on this pipeline includes oil produced by us and our working interest partner in South Timbalier 26. EPL Pipeline, L.L.C. has on file with the Louisiana Public Service Commission and FERC tariffs for this transportation service and offers non-discriminatory transportation for any willing shipper.

***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 estimated 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. As of December 31, 2004 and 2003, we had $45.1 million and $40.6 million, respectively, reflected in our consolidated balance sheets for estimated future abandonment.

**Additional Factors Affecting Business**

*Risks Relating to the Oil and Natural Gas Industry*

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

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

- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions, such as hurricanes and tropical storms;
- reductions in oil and natural gas prices;
- title problems; and
- limitations in the market for oil and natural gas.

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

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

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

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

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company. We maintain insurance at levels that we believe are consistent with industry practices and our particular needs, but we are not fully insured against all risks. We may elect not to obtain insurance 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 our cash flow and net income and could reduce or eliminate the funds available for exploration, exploitation and acquisitions or result in loss of equipment and properties.

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

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include:

- changes in the global supply, demand and inventories of oil;
- domestic natural gas supply, demand and inventories;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the price and quantity of foreign imports of oil;
- the price and availability of liquefied natural gas imports;
- political conditions, including embargoes, in or affecting other oil-producing countries;
- economic and energy infrastructure disruptions caused by actual or threatened acts of war, or terrorist activities, or national security measures deployed to protect the United States from such actual or threatened acts or activities;
- economic stability of major oil and natural gas companies and the interdependence of oil and natural gas and energy trading companies;
- the level of worldwide oil and natural gas exploration and production activity;
- 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, ability to finance planned capital expenditures or ability to pursue acquisitions. Further, oil prices and natural gas prices do not necessarily move together.

***Reserve estimates depend on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.***

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this Report.

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

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

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

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

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

*Risks Relating to Energy Partners, Ltd.*

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

During the month of December 2004, 32% of our net daily production came from our East Bay field. If mechanical problems, storms or other events were to curtail a substantial portion of this production, our cash flow would be affected adversely. Also, at December 31, 2004, approximately 39% of our proved reserves were located on this property. In addition, at December 31, 2004 approximately 34% of our proved reserves were located in our Greater Bay Marchand area. If the actual reserves associated with these properties are less than our estimated reserves, our business, financial condition or results of operations could be adversely affected.

***Relatively short production life for Gulf of Mexico region 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 in the Gulf of Mexico region. Production from reserves in reservoirs in the Gulf of Mexico region generally declines more rapidly than from reservoirs in many other producing regions of the world. As of December 31, 2004, or independent petroleum engineers estimate, on average, 69% of our total proved reserves will be produced within 5 years. As a result, our reserve replacement needs from new investments are relatively greater than those of producers who recover lower percentages of their reserves over a similar time period, such as producers who have a portion of their reserves outside the Gulf of Mexico in areas where the rate of reserve production is lower. We may not be able to develop, exploit, find or acquire additional reserves to sustain our current production levels or to grow. There can be no assurance that we will be able to grow production at rates we have experienced in the past. Our future oil and natural gas reserves and production, and, therefore, our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

***Rapid growth may place significant demands on our resources.***

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

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

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

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

Our strategy includes acquisitions. The successful acquisition of producing properties requires assessments of many factors, which are inherently inexact and may be inaccurate, including:

- the amount of recoverable reserves and the rates at which those reserves will be produced;
- future oil and natural gas prices;
- estimates of operating costs;
- estimates of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- potential environmental and other liabilities.

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

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

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

***The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute on a timely basis our exploration and development plans within our budget.***

All of our operations are in the Gulf of Mexico region. 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, as a result of increased drilling activity or a decrease in the supply of equipment, materials and services, we have experienced increases in associated costs, including those related to drilling rigs, equipment, supplies and personnel and the services and products of other vendors to the industry. Increased drilling activity in the Gulf of Mexico 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 organization documents and under Delaware law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock.***

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

- the board of directors' ability to issue shares of preferred stock and determine the terms of the preferred stock without approval of common stockholders; and
- a prohibition on the right of stockholders to call meetings and a limitation on the right of stockholders to act by written consent and to present proposals or make nominations at stockholder meetings.

In addition, Delaware law imposes some restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock.

***The loss of key personnel could adversely affect us.***

To a large extent, we depend on the services of our 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 exploration and production business is highly competitive, and our success will depend largely on our ability to attract and retain experienced geoscientists and other professional staff.

***Competition in the oil and natural gas industry is intense, which may adversely affect us.***

We operate in a highly competitive environment for acquiring oil and natural gas properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in Gulf of Mexico activities. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We cannot make assurances that we will be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital. If we are unable to compete successfully in these areas in the future, our future revenues and growth may be diminished or restricted.

### Significant Customers

We market substantially all of the oil and natural gas from properties we operate and from properties others operate where our interest is significant. A majority of oil production from the East Bay field is sold under a contract with Shell Trading (US) Company ("Shell"). The contract has a 60 day cancellation provision and can be 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 Global Trading ("ChevronTexaco") and Shell. Currently, the most significant purchaser of our natural gas production is Louis Dreyfus Energy Services, L.P. ("Dreyfus"). We believe that the prices for liquids and natural gas are comparable to market prices in the areas where we have production. 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 2004, Shell accounted for approximately 22 percent, Dreyfus 14 percent and ChevronTexaco 13 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, 2004, we had 151 full-time employees, including 42 geoscientists, engineers and technicians and 48 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 | 60 | Chairman, President and Chief Executive Officer |
| Suzanne V. Baer | 57 | Executive Vice President and Chief Financial Officer |
| Phillip A. Gobe | 52 | Executive Vice President and Chief Operating Officer |
| John H. Peper | 52 | Executive Vice President, General Counsel and Corporate Secretary |
| T. Rodney Dykes | 48 | Senior Vice President — Production |
| William Flores, Jr. | 47 | 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 has also been nominated to become a director of Trico Marine Services, Inc.

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 35 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. Subsequent to the year ended December 31, 2004 Ms. Baer announced her plan to retire in April 2005. Her successor, David R. Looney, began service in February 2005 and will become our new chief financial officer following their transition period and his appointment by our Board of Directors.

Phillip A. Gobe joined us in December 2004 as chief operating officer. Mr. Gobe has over 28 years of energy industry experience and was with Nuevo Energy Company as chief operating officer from February 2001 until its acquisition by Plains Exploration & Production Company in May 2004. Mr. Gobe's primary responsibilities were managing Nuevo's domestic and international exploitation and exploration operations. Prior to his position with Nuevo, Mr. Gobe had been the Senior Vice President of Production for Vastar Resources, Inc. since 1997. From 1976 to 1997, Mr. Gobe worked for Atlantic Richfield Company and its subsidiaries in positions of increasing responsibility, primarily in the Gulf of Mexico and Alaska.

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.

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 |
|---|---|---|
| 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 | 14.81 | 12.60 |
| Second Quarter | 15.45 | 12.60 |
| Third Quarter | 16.59 | 14.00 |
| Fourth Quarter | 20.91 | 16.07 |
| 2005 | | |
| First Quarter (through February 25, 2005) | 26.16 | 18.38 |

On February 25, 2005 the last reported sale price of our common stock on the New York Stock Exchange was $25.65 per share.

As of February 25, 2005 there were approximately 100 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, | | | | |
|---|---|---|---|---|---|
| | 2004 | 2003 | 2002 | 2001 | 2000 |
| | (In thousands, except per share data) | | | | |
| Statement of Operations Data: | | | | | |
| Revenue | $ 295,210 | $ 230,187 | $133,788 | $ 146,240 | $ 111,017 |
| Income (loss) from operations(1) | 86,068 | 58,560 | (6,600) | 20,663 | (940) |
| Net income (loss)(2) | 46,416 | 33,250 | (8,799) | 11,974 | (18,684) |
| Net income (loss) available to common stockholders(3) | 43,017 | 29,705 | (12,129) | 11,974 | (25,387) |
| Basic net income (loss) per common share | $ 1.31 | $ 0.96 | $ (0.44) | $ 0.45 | $ (2.27) |
| Diluted net income (loss) per common share | $ 1.20 | $ 0.93 | $ (0.44) | $ 0.44 | $ (2.27) |
| Cash flows provided by (used in): | | | | | |
| Operating activities | $ 165,074 | $ 136,702 | $ 25,417 | $ 91,847 | $ 50,703 |
| Investing activities | (176,713) | (110,057) | (54,380) | (121,067) | (130,378) |
| Financing activities | 784 | 77,631 | 29,079 | 25,871 | 60,742 |

| | As of December 31, | | | | |
|---|---|---|---|---|---|
| | 2004 | 2003 | 2002 | 2001 | 2000 |
| | (In thousands) | | | | |
| Balance Sheet Data: | | | | | |
| Total assets | $647,678 | $544,181 | $384,220 | $242,777 | $208,149 |
| Long-term debt, excluding current maturities | 150,109 | 150,317 | 103,687 | 25,408 | 100 |
| Stockholders' equity | 315,049 | 261,485 | 191,922 | 164,867 | 150,591 |
| 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 $3.4 million, $3.5 million and $3.3 million from net income (loss) for the years ended December 31, 2004, 2003 and 2002, respectively; and by subtracting preferred stock dividends and accretion of issuance costs of $6.7 million for the year ended December 31, 2000.

**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 in 2004 were concentrated in the shallow to moderate depth waters of the Gulf of Mexico Shelf. In January 2005 we extended our operations into the Gulf Coast onshore region through an acquisition of properties in South Louisiana.

In 2004, we achieved another year of growth and reported the best year on a revenue and net income as well as per-share basis over our seven-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, including 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 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. ("EIF"). After payment of underwriting discounts and commissions, the offering generated net proceeds to us of approximately $38.0 million. After expenses of approximately $0.5 million, the proceeds were used to repay a portion of outstanding borrowings under our bank credit facility.

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

On 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 was set aside for general corporate purposes, including acquisitions. In October 2003, we consummated an exchange offer pursuant to which we exchanged registered Senior Notes having substantially identical terms as the Senior Notes for the privately placed Senior Notes.

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.

On July 16, 2004, we filed a universal shelf registration statement which allowed us to issue an aggregate of $300 million in common stock, preferred stock, senior debt and subordinated debt in one or more separate offerings with the size, price and terms to be determined at the time of the sale. On November 10, 2004 we sold approximately 3.5 million shares of our common stock to the public pursuant to this shelf registration statement, leaving us with the ability to issue an additional $239.6 million of securities under the shelf registration statement. Concurrent with this offering, we entered into a stock purchase agreement with EIF in which we purchased approximately 3.5 million shares of common stock owned by EIF at a price per share equal to the net proceeds per share received in the offering, before expenses. We did not retain any of the proceeds from the offering and the shares are now held as treasury shares, at cost. We have no immediate plans to enter into any additional transactions under this registration statement, but plan to use the proceeds of any future offering under this registration statement for general corporate purposes, which may include debt repayment, acquisitions, expansion and working capital.

On August 3, 2004 we amended and extended to August 3, 2008 our bank credit facility. Under the amendment our initial borrowing base remained $60 million. The borrowing base was increased to $150 million at the time of our purchase of south Louisiana properties and reserves in January 2005. The borrowing base will remain subject to redetermination based on the proved reserves of the oil and natural gas properties that serve as collateral for the bank credit facility.

Our 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 2005, strong commodity prices, together with growing production volumes, should enable us to adhere to our policy of funding our exploration and development expenditures with internally generated cash flow. This strategy allows us to preserve our strong balance sheet to finance acquisitions and other capital intensive projects that might result from our exploration and development activities. In addition to the south Louisiana property acquisition already completed in 2005, we believe this year will provide us a number of opportunities to acquire targeted properties, including those within our focus area.

## Results of Operations

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| Net production (per day): | | | |
| Oil (Bbls) | 8,663 | 7,978 | 8,148 |
| Natural gas (Mcf) | 82,098 | 78,596 | 54,150 |
| Total (Boe) | 22,346 | 21,077 | 17,173 |
| Oil & natural gas revenues (in thousands): | | | |
| Oil | $111,006 | $ 81,599 | $ 70,311 |
| Natural gas | 183,525 | 148,104 | 63,835 |
| Total | 294,531 | 229,703 | 134,146 |
| Average sales prices, net of hedging: | | | |
| Oil (per Bbl) | $ 35.01 | $ 28.02 | $ 23.64 |
| Natural gas (per Mcf) | 6.11 | 5.16 | 3.23 |
| Total (per Boe) | 36.01 | 29.86 | 21.40 |
| Impact of hedging: | | | |
| Oil (per Bbl) | $ (4.40) | $ (1.67) | $ (0.51) |
| Natural gas (per Mcf) | (0.04) | (0.23) | (0.18) |
| Average costs (per Boe): | | | |
| Lease operating expense | $ 4.97 | $ 4.77 | $ 5.49 |
| Taxes, other than on earnings | 1.13 | 0.99 | 1.05 |
| Depreciation, depletion and amortization | 11.29 | 10.65 | 10.29 |
| Increase (decrease) in oil and natural gas revenue (net of hedging) due to: | | | |
| Change in prices of oil | $ 22,160 | $ 13,027 | |
| Change in production volumes of oil | 7,247 | (1,739) | |
| Total increase in oil sales | 29,407 | 11,288 | |
| Change in prices of natural gas | $ 28,396 | $ 38,183 | |
| Change in production volumes of natural gas | 7,025 | 46,086 | |
| Total increase in natural gas sales | 35,421 | 84,269 | |

| | As of December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| Total estimated net proved reserves: | | | |
| Oil (Mbbls) | 28,770 | 27,414 | 26,353 |
| Natural gas (Mmcf) | 149,835 | 134,404 | 126,957 |
| Total (Mboe) | 53,743 | 49,815 | 47,513 |
| Present value of estimated future net cash flows before income taxes (in thousands) | $924,135 | $701,237 | $608,273 |
| Standardized measure of discounted future net cash flows (in thousands) | $667,668 | $529,415 | $476,901 |

### *Revenues and Net Income*

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

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.

We recognized net income of $46.4 million in 2004 compared to net income of $33.3 million in 2003. The increase in net income 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 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. The following items had a significant impact on our net income or loss in 2004, 2003 and 2002 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.

### *Operating Expenses*

Operating expenses were impacted by the following:

- Lease operating expense increased $3.9 million to $40.6 million in 2004. This is a result of the addition of production from new fields and $1.0 million related to the retained loss portion of repairs due to Hurricane Ivan.

  Lease operating expense increased $2.3 million to $36.7 million in 2003. This was 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 decreased due to the lower fixed costs required for these new fields.

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

  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.

- Exploration expenditures increased $18.5 million to $35.9 million in 2004. The expense in 2004 is primarily the result of an increase in dry hole charges of $10.9 million to $21.0 million as a result of exploratory wells drilled during the year which were found to be noncommercial, as well as property impairments of $6.9 million at our East Cameron 378 field and seismic expenditures and delay rentals which increased $3.5 million to $8.0 million. Our exploration expenditures, including dry hole charges will vary depending on the amount of our capital budget dedicated to exploration activities and the level of success we achieve in exploratory drilling activities. Although our dry hole costs were higher in 2004, we allocated more dollars to exploration in 2004 while maintaining a comparable success rate.

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 noncommercial, 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. Although our dry hole costs were higher in 2003, we allocated more dollars to exploration in 2003 while maintaining a comparable success rate.

- Depreciation, depletion and amortization increased $10.5 million to $92.4 million in 2004. The increase was due to the increased depreciable asset base combined with higher production and a shift in the production contribution from our various fields. 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 $6.6 million of amortization for our asset retirement obligation for 2004 as compared to $5.2 million in 2003.

  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. This expense includes $5.2 million of amortization for our asset retirement obligation for 2003 as compared to $6.8 million in 2002.

- Other general and administrative expenses increased $1.2 million to $27.9 million in 2004. The increase was primarily due to increased consulting costs ($1.9 million), of which $0.4 million was increased costs paid to our internal audit service provider and external auditors to implement the requirements of Section 404 of the Sarbanes-Oxley Act of 2002. The remainder included increased human resources, land and engineering consulting costs. This was offset by decreased casualty insurance ($0.4 million) and decreased technology costs ($0.2 million).

  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.

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

  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 shares and the granting of performance share awards to employees.

### *Other Income and Expense*

Interest expense increased $4.2 million to $14.4 million in 2004. 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 in 2003.

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.

## Financial Condition, Liquidity and Capital Resources

The increase in revenues we experienced in 2004 increased our cash flows from operations, which totaled $165.1 million. We intend to fund our exploration and development expenditures from internally generated cash flows, which we define as cash flows from operations before consideration of changes in working capital plus total exploration expenditures. Our cash on hand at December 31, 2004 was $93.5 million, substantially all of which was used in the purchase of the south Louisiana properties in January 2005. 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 August 3, 2004, consists of a revolving line of credit with a group of banks available through August 3, 2008 (the "bank credit facility"). The bank credit facility had a borrowing base of $60 million. The borrowing base was increased to $150 million at the time of our purchase of south Louisiana properties and reserves in January 2005. The bank credit facility is subject to redetermination based on the proved reserves of the oil and natural gas properties that serve as collateral for the bank credit facility as set out in the reserve report delivered to the banks each April 1 and October 1. The bank credit facility permits both prime rate 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 credit facility. The spread can range from 1.25% to 2.00% above LIBOR and 0% to 0.75% above prime. The borrowing base under the bank credit facility is secured by substantially all of our assets. We used our bank credit facility to fund a portion of the purchase of the south Louisiana properties in January 2005 and the acquisition of the additional interest in South Timbalier 26 in March 2005. As a result at March 8, 2005, we had $70.0 million outstanding and $80.0 million of credit capacity available under the bank credit facility. In addition, we pay an annual fee on the unused portion of the bank credit facility ranging between 0.375% to 0.5% based on utilization. The bank credit facility contains customary events of default and various financial covenants, which require us to: (i) maintain a minimum current ratio of 1.0 as defined in our bank credit facility agreement, and (ii) maintain a minimum EBITDAX to interest ratio of 3.5 times. We were in compliance with these covenants as of December 31, 2004.

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 was 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 financing 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 $176.7 million used in investing activities in 2004 primarily included oil and natural gas property capital and exploration expenditures of $163.0 million, lease acquisitions of $6.6 million and a deposit of $5.0 million paid for the January 2005 purchase of south Louisiana reserves and prospects from Castex. Exploration expenditures incurred are excluded from operating cash flows and included in investing activities. During 2004, we completed 31 drilling projects and 21 recompletion/workover projects, 41 of which were successful. During 2003, we completed 23 drilling projects and 33 recompletion/workover projects, 46 of which were successful.

Our 2005 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, including the acquisitions of properties and reserves to date in 2005. We currently intend to allocate approximately 55% of our budget on low risk development and exploitation activities, approximately 30% to moderate risk exploration opportunities and approximately 15% to higher risk, higher potential exploration opportunities. Our exploration and development budget for 2005 is currently $240 million, inclusive of expected expenditures on the properties acquired in January 2005. 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 2005 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, 2004:

| | Payments Due by Period | | | | |
|---|---|---|---|---|---|
| | Total | Less than 1 Year | 1-3 Years | 3-5 Years | Thereafter |
| | | | (In thousands) | | |
| Long-term debt | $150,217 | $ 108 | $ 109 | $ — | $150,000 |
| Interest attributable to all long-term debt(1) | 73,295 | 13,139 | 26,250 | 26,250 | 7,656 |
| Operating leases | 13,865 | 3,542 | 4,877 | 3,431 | 2,015 |
| Unconditional purchase obligations(2) | 3,589 | 2,899 | 690 | — | — |
| Other long-term liabilities | 1,270 | — | — | — | 1,270 |
| Total contractual obligations | $242,236 | $19,688 | $31,926 | $29,681 | $160,941 |

(1) At December 31, 2004 there was no outstanding debt with variable interest rates.

(2) 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, 2004:

**Natural Gas Positions**

| Remaining Contract Term | Contract Type | Strike Price ($/Mmbtu) | Volume (Mmbtu) Daily | Volume (Mmbtu) Total |
|---|---|---|---|---|
| 01/05 - 12/05 .................... | Collar | $ 4.50/$10.75 | 20,000 | 7,300,000 |

**Crude Oil Positions**

| Remaining Contract Term | Contract Type | Strike Price ($/Bbl) | Volume (Bbls) Daily | Volume (Bbls) Total |
|---|---|---|---|---|
| 1/05 - 12/05 ..................... | Collar | $31.00/$44.05 | 2,000 | 730,000 |

Subsequent to December 31, 2004, we entered into the following contracts:

**Natural Gas Positions**

| Remaining Contract Term | Contract Type | Strike Price ($/Mmbtu) | Volume (Mmbtu) Daily | Volume (Mmbtu) Total |
|---|---|---|---|---|
| 07/05 - 12/05 .................... | Collar | $ 5.00/$10.00 | 15,000 | 2,760,000 |
| 01/06 - 12/06 .................... | Collar | $ 5.00/$9.51 | 15,000 | 5,475,000 |
| 01/07 - 12/07 .................... | Collar | $ 5.00/$8.00 | 10,000 | 3,650,000 |

Accounting and reporting standards require that derivative instruments, including certain derivative instruments embedded in other contracts, be recorded at fair market value and included as either assets or liabilities in the balance sheet. The accounting for changes in fair value depends on the intended use of the derivative and the resulting designation, which is established at the inception of the derivative. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the statement of operations. For derivative instruments designated as cash-flow hedges, changes in fair value, to the extent the hedge is effective, will be recognized in other comprehensive income (a component of stockholders' equity) until the forecasted transaction is settled, when the resulting gains and losses will be recorded in earnings. Hedge ineffectiveness is measured at least quarterly based on the changes in fair value between the derivative contract and the hedged item. Any change in fair value resulting from ineffectiveness is charged currently to other revenue.

Our hedged volume as of December 31, 2004 approximated 22% 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 as a pool of total oil and natural gas property costs.

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

  It is typical for companies that have an active exploratory drilling program, as we do, to incur dry hole costs. During the last three years we have drilled 61 exploration wells, of which 12 were considered dry holes. Our dry hole costs charged to expense during this period totaled $36.9 million out of total exploratory drilling costs of $200.5 million. It is impossible to predict future dry holes; however we expect to continue to have dry hole costs in the future which will vary depending on the amount of our capital dedicated to exploration activities and on the level of success of our exploratory program.

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

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

  At December 31, 2004, proved oil and natural gas reserves were 53.7 million barrels of oil-equivalent ("Mmboe"). Approximately 69 percent of our proved reserves are classified as either proved undeveloped or proved developed non-producing reserves. Most of our proved developed non-producing reserves are "behind pipe" and will be produced after depletion of another horizon in the same well. Approximately 22 percent of total proved reserves are categorized as proved undeveloped reserves. As of December 31, 2004, 69 percent of our proved undeveloped reserves were under development and expected to become proved developed within one year.

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

The computation of the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves at December 31, 2004 was based on period-end prices of $6.23 per Mcf for natural gas and $41.84 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.

- *Depletion, Depreciation, and Amortization of Oil and Natural Gas Properties* — We calculate depletion, depreciation, and amortization expense ("DD&A") using the estimates of proved oil and natural gas reserves previously discussed in these critical accounting policies. We segregate the costs for individual or contiguous properties or projects and record DD&A for these property costs separately using the units of production method. The units of production method is calculated as the ratio of (1) actual volumes produced to (2) total proved developed reserves (those proved reserves recoverable through existing wells with existing equipment and operating methods) applied to (3) asset cost. The volumes produced and asset cost are known, and while proved developed reserves are reasonably certain, they are based on estimates that are subject to some variability. This variability can result in net upward or downward revisions of proved developed reserves in existing fields, as more information becomes available through research and production and as a result of changes in economic condition. Our revisions over the past three years, in each case either positive or negative have been less than 5% of total proved reserves on a barrel of oil equivalent basis. While the revisions we have made in the past are an indicator of variability, they have had a minimal impact on the units of production rates because they have been low compared to our reserve base. Actual historical revisions are not necessarily indicative of future variability.

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

  We base our assessment of possible impairment using our best estimate of future prices, costs and expected net cash flow generated by a property. We estimate future prices based on management's expectations and escalate both the prices and the costs for inflation if appropriate. If these undiscounted estimates indicate an impairment, we measure the impairment expense as the difference between the net book value of the asset and its estimated fair value measured by discounting the future net cash flow from the property at an appropriate rate. Actual prices, costs, discount rates, and net cash flow may vary from our estimates. An estimate as to the sensitivity to earnings resulting from impairment reviews and impairment calculations is not practicable, given the broad range in the cost structure of our oil and natural gas assets and the number of assumptions involved in the estimates. That is, favorable changes to some assumptions may avoid the need to impair any assets, whereas unfavorable changes might cause some assets to become impaired but not others. We recognized impairment expense of $6.9 million, $2.8 million and none in the years ending December 31, 2004, 2003 and 2002. The impairment in 2004 consisted of one field which incurred significant capital costs in excess of those anticipated. Two fields were fully impaired in 2003 due to mechanical problems.

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. If we do not find commercial oil and natural gas reserves, the related unamortized capitalized costs will be charged to earnings when the determination is made.

- *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. 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 market prices change, the other party to the contract defaults on its obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

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 2004, the FASB issued Statement of Financial Accounting Standards No. 151 "Inventory Costs, an amendment of ARB No. 43, Chapter 4" ("Statement 151"). The amendments made by Statement 151 clarify that abnormal amounts of idle facility expense, freight, handling costs, and wasted materials (spoilage) should be recognized as current-period charges and require the allocation of fixed production overheads to inventory based on the normal capacity of the production facilities. The guidance is effective for inventory costs incurred during fiscal years beginning after June 15, 2005. Earlier application is permitted for inventory costs incurred during fiscal years beginning after November 23, 2004. Our assessment of the provisions of Statement 151 is that it is not expected to have an impact on our financial position, results of operations or cash flows.

In December 2004, the FASB issued Statement of Financial Accounting Standards No. 152 "Accounting for Real Estate Time-Sharing Transactions — An Amendment to FASB Statements No. 66 and 67" ("Statement No. 152"). Statement 152 amends FASB Statement No. 66, "Accounting for Sales of Real Estate," to reference the financial accounting and reporting guidance for real estate time-sharing transactions that is provided in AICPA Statement of Position (SOP) 04-2, "Accounting for Real Estate Time-Sharing Transactions." Statement 152 also amends FASB Statement No. 67, "Accounting for Costs and Initial Rental Operations of Real Estate Projects," to state that the guidance for (a) incidental operations and (b) costs incurred to sell real estate projects does not apply to real estate time-sharing transactions. The accounting for those operations and costs is subject to the guidance in SOP 04-2. Statement 152 is effective for financial statements for fiscal years beginning after June 15, 2005. Our assessment of the provisions of Statement 152 is that it is not expected to have an impact on our financial position, results of operations or cash flows.

In December 2004, the FASB issued Statement of Financial Accounting Standards No. 153 "Exchanges of Non-monetary assets — an amendment of APB Opinion No. 29" ("Statement 153"). Statement 153 amends Accounting Principles Board ("APB") Opinion 29 to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. Statement 153 does not apply to a pooling of assets in a joint undertaking intended to fund, develop, or produce oil or natural gas from a particular property or group of properties. The provisions of Statement 153 shall be effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. Early adoption is permitted and the provisions of Statement 153 should be applied prospectively. Our assessment of the provisions of Statement 153 is that it is not expected to have an impact on our financial position, results of operations or cash flows.

In December 2004, the FASB issued Statement of Financial Accounting Standards No. 123-Revised 2004, "Share-Based Payment," ("Statement 123R"). This is a revision of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation", and supersedes APB No. 25, "Accounting for Stock Issued to Employees." We currently account for stock-based compensation under the provisions of APB 25. Under Statement 123R, we will be required to measure the cost of employee services received in exchange for stock, based on the grant-date fair value (with limited exceptions). That cost will be recognized as expense over the period during which an employee is required to provide service in exchange for the award (usually the vesting period). The fair value will be estimated using an option-pricing model. Excess tax benefits, as defined in Statement 123R, will be recognized as an addition to paid-in capital. This is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. We are currently in the process of evaluating the impact of Statement 123R on our financial statements, including different option-pricing models. Note (2)(j) of the Notes to Consolidated Financial Statements illustrates the current effect on net income and earnings per share if we had applied the fair value recognition provisions of Statement 123.

## 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, 2004, none of our outstanding long-term debt had variable 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, 2004, we had the following contracts in place:

**Natural Gas Positions**

| | | | Volume (Mmbtu) | |
|---|---|---|---|---|
| **Remaining Contract Term** | **Contract Type** | **Strike Price ($/Mmbtu)** | **Daily** | **Total** |
| 01/05 - 12/05 .................... | Collar | $ 4.50/$10.75 | 20,000 | 7,300,000 |

**Crude Oil Positions**

| | | | Volume (Bbls) | |
|---|---|---|---|---|
| **Remaining Contract Term** | **Contract Type** | **Strike Price ($/Bbl)** | **Daily** | **Total** |
| 1/05 - 12/05 ..................... | Collar | $31.00/$44.05 | 2,000 | 730,000 |

Subsequent to December 31, 2004, we entered into the following contracts:

**Natural Gas Positions**

| | | | Volume (Mmbtu) | |
|---|---|---|---|---|
| **Remaining Contract Term** | **Contract Type** | **Strike Price ($/Mmbtu)** | **Daily** | **Total** |
| 07/05 - 12/05 .................... | Collar | $ 5.00/$10.00 | 15,000 | 2,760,000 |
| 01/06 - 12/06 .................... | Collar | $ 5.00/$9.51 | 15,000 | 5,475,000 |
| 01/07 - 12/07 .................... | Collar | $ 5.00/$8.00 | 10,000 | 3,650,000 |

Our hedged volume as of December 31, 2004 approximated 22% of our estimated production from proved reserves through the balance of the terms of the contracts. Had these contracts been terminated at December 31, 2004, we estimate the loss would have been $1.7 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, 2004 and 2003, the potential change in the fair value of commodity derivative instruments assuming a 10% increase in the underlying commodity price was a $2.4 million and $4.1 million increase in the combined estimated loss, respectively.

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.

"proved undeveloped reserves" Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

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

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

"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***

## MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Board of Directors and Stockholders
Energy Partners, Ltd.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Our internal control system was designed to provide reasonable assurance to the Company's management and Board of Directors regarding the reliability of financial reporting and the presentation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles. Under the supervision and with the participation of our management, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2004. No matter how well designed, there are inherent limitations in all systems of internal control. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which is included herein, which expresses unqualified opinions on management's assessment and on the effectiveness of our internal control over financial reporting as of December 31, 2004.

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

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

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM — INTERNAL CONTROL OVER FINANCIAL REPORTING

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

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Energy Partners, Ltd. maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Energy Partners, Ltd.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Energy Partners, Ltd. maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, Energy Partners, Ltd. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Energy Partners, Ltd. and subsidiaries as of December 31, 2004 and 2003, 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, 2004. In connection with our audits of the consolidated financial statements, we also have audited the accompanying financial statement schedule, "Valuation and Qualifying Accounts," for the years ended December 31, 2004, 2003, and 2002. Our report dated March 13, 2005 expressed an unqualified opinion on those consolidated financial statements and schedule.

KPMG LLP

New Orleans, Louisiana
March 13, 2005

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM — CONSOLIDATED FINANCIAL STATEMENTS

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, 2004 and 2003, and the related consolidated statement of operations, changes in stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2004. In connection with our audits of the consolidated financial statements, we also have audited the accompanying financial statement schedule, "Valuation and Qualifying Accounts," for the years ended December 31, 2004, 2003, and 2002. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Energy Partners, Ltd. and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Energy Partners, Ltd.'s internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 13, 2005, expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

New Orleans, Louisiana
March 13, 2005

## ENERGY PARTNERS, LTD. AND SUBSIDIARIES

### CONSOLIDATED BALANCE SHEETS
**December 31, 2004 and 2003**
**(In thousands, except share data)**

| | 2004 | 2003 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 93,537 | $ 104,392 |
| Trade accounts receivable — net of allowance for doubtful accounts of none in 2004 and $26 in 2003 | 59,341 | 35,315 |
| Other receivables | 5,600 | — |
| Deferred tax assets | 1,906 | 2,939 |
| Prepaid expenses | 2,285 | 2,106 |
| Total current assets | 162,669 | 144,752 |
| Property and equipment, at cost under the successful efforts method of accounting for oil and gas properties | 769,331 | 598,101 |
| Less accumulated depreciation, depletion and amortization | (304,997) | (210,013) |
| Net property and equipment | 464,334 | 388,088 |
| Other assets | 15,970 | 6,575 |
| Deferred financing costs — net of accumulated amortization of $4,174 in 2004 and $3,267 in 2003 | 4,705 | 4,766 |
| | $ 647,678 | $ 544,181 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| Current liabilities: | | |
| Accounts payable | $ 21,255 | $ 14,650 |
| Accrued expenses | 59,387 | 42,487 |
| Fair value of commodity derivative instruments | 1,749 | 3,814 |
| Current maturities of long-term debt | 108 | 99 |
| Total current liabilities | 82,499 | 61,050 |
| Long-term debt | 150,109 | 150,317 |
| Deferred tax liabilities | 53,686 | 29,584 |
| Asset retirement obligation | 45,064 | 40,577 |
| Other | 1,271 | 1,168 |
| | 332,629 | 282,696 |
| Stockholders' equity: | | |
| Preferred stock, $1 par value. Authorized 1,700,000 shares; issued and outstanding: 2004 — 344,399 shares; 2003 — 368,076 shares. Aggregate liquidation value: 2004 — $34,440; 2003 $36,808 | 33,504 | 34,894 |
| Common stock, par value $0.01 per share. Authorized 50,000,000 shares; issued and outstanding: 2004 — 36,618,084 shares; 2003 — 32,241,981 shares | 367 | 323 |
| Additional paid-in capital | 296,460 | 228,511 |
| Accumulated other comprehensive loss — net of deferred taxes of $630 in 2004 and $1,373 in 2003 | (1,119) | (2,441) |
| Retained earnings | 43,215 | 198 |
| Treasury stock, at cost. 2004 — 3,480,441 shares; 2003 — no shares | (57,378) | — |
| Total stockholders' equity | 315,049 | 261,485 |
| Commitments and contingencies | | |
| | $ 647,678 | $ 544,181 |

See accompanying notes to consolidated financial statements.

## ENERGY PARTNERS, LTD. AND SUBSIDIARIES

## CONSOLIDATED STATEMENTS OF OPERATIONS

**Years Ended December 31, 2004, 2003 and 2002**

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

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Revenue: | | | |
| Oil and natural gas | $294,531 | $229,703 | $134,146 |
| Other | 679 | 484 | (358) |
| | 295,210 | 230,187 | 133,788 |
| Costs and expenses: | | | |
| Lease operating | 40,617 | 36,693 | 34,400 |
| Taxes, other than on earnings | 9,263 | 7,650 | 6,572 |
| Exploration expenditures and dry hole costs | 35,935 | 17,353 | 10,735 |
| Depreciation, depletion and amortization | 92,353 | 81,927 | 64,513 |
| General and administrative: | | | |
| Stock-based compensation | 3,050 | 1,285 | 453 |
| Severance costs | — | — | 1,211 |
| Other general and administrative | 27,924 | 26,719 | 22,504 |
| Total costs and expenses | 209,142 | 171,627 | 140,388 |
| Income (loss) from operations | 86,068 | 58,560 | (6,600) |
| Other income (expense): | | | |
| Interest income | 1,219 | 380 | 107 |
| Interest expense | (14,355) | (10,174) | (6,988) |
| | (13,136) | (9,794) | (6,881) |
| Income (loss) before income taxes and cumulative effect of change in accounting principle | 72,932 | 48,766 | (13,481) |
| Income taxes | (26,516) | (17,784) | 4,682 |
| Net income (loss) before cumulative effect of change in accounting principle | 46,416 | 30,982 | (8,799) |
| Cumulative effect of change in accounting principle, net of income taxes of $1,276 | — | 2,268 | — |
| Net income (loss) | 46,416 | 33,250 | (8,799) |
| Less dividends earned on preferred stock and accretion of discount | (3,399) | (3,545) | (3,330) |
| Net income (loss) available to common stockholders | $ 43,017 | $ 29,705 | $(12,129) |
| Earnings per share: | | | |
| Basic: | | | |
| Before cumulative effect of change in accounting principle | $ 1.31 | $ 0.89 | $ (0.44) |
| Cumulative effect of change in accounting principle | — | 0.07 | — |
| Basic earnings (loss) per share | $ 1.31 | $ 0.96 | $ (0.44) |
| Diluted: | | | |
| Before cumulative effect of change in accounting principle | $ 1.20 | $ 0.87 | $ (0.44) |
| Cumulative effect of change in accounting principle | — | 0.06 | — |
| Diluted earnings (loss) per share | $ 1.20 | $ 0.93 | $ (0.44) |
| Weighted average common shares used in Computing income (loss) per share: | | | |
| Basic | 32,861 | 30,822 | 27,467 |
| Incremental common shares | 5,788 | 4,753 | — |
| Diluted | 38,649 | 35,575 | 27,467 |

See accompanying notes to consolidated financial statements.

## ENERGY PARTNERS, LTD. AND SUBSIDIARIES

## CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
### Years Ended December 31, 2004, 2003 and 2002
### (In thousands)

| | Preferred Stock Shares | Preferred Stock | Treasury Stock Shares | Treasury Stock | Common Stock Shares | Common Stock | Additional Paid-In Capital | Accumulated Other Comprehensive Income | Retained Earnings (Deficit) | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Balance at December 31, 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 public offering, net of costs | — | — | — | — | 4,211 | 42 | 37,535 | — | — | 37,577 |
| Exercise of common stock options | — | — | — | — | 167 | 2 | 2,148 | — | — | 2,150 |
| Conversion 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 |
| Stock-based compensation | — | — | — | — | 81 | — | 1,782 | — | — | 1,782 |
| Shares cancelled | — | — | 13 | — | (116) | — | (147) | — | — | (147) |
| Proceeds from public offering, net of costs | — | — | — | — | 3,467 | 35 | 57,343 | — | — | 57,378 |
| Exercise of common stock options | — | — | — | — | 453 | 5 | 3,906 | — | — | 3,911 |
| Tax impact of exercise of stock options | — | — | — | — | — | — | 1,974 | — | — | 1,974 |
| Equity offering costs | — | — | — | — | — | — | (106) | — | — | (106) |
| Purchase of shares into treasury | — | — | 3,467 | (57,378) | — | — | — | — | — | (57,378) |
| Conversion of warrants into common stock | — | — | — | — | 175 | 1 | 319 | — | — | 320 |
| Conversion of preferred stock | (24) | (2,368) | — | — | 277 | 2 | 2,366 | — | — | — |
| Common stock issued to 401(K) plan | — | — | — | — | 13 | — | 207 | — | — | 207 |
| Dividends on preferred stock | — | — | — | — | — | — | — | — | (2,421) | (2,421) |
| Accretion of discount on preferred stock | — | 978 | — | — | — | — | — | — | (978) | — |
| Comprehensive income: | | | | | | | | | | |
| Net income | — | — | — | — | — | — | — | — | 46,416 | 46,416 |
| Fair value of commodity derivative instruments | — | — | — | — | — | — | — | 1,322 | — | 1,322 |
| Comprehensive income | | | | | | | | | | 47,738 |
| Other | — | — | — | — | 26 | 1 | 305 | — | — | 306 |
| Balance at December 31, 2004 | 344 | $33,504 | 3,480 | $(57,378) | 36,618 | $367 | $296,460 | $(1,119) | $ 43,215 | $315,049 |

See accompanying notes to consolidated financial statements.

## ENERGY PARTNERS, LTD. AND SUBSIDIARIES

## CONSOLIDATED STATEMENTS OF CASH FLOWS

**Years Ended December 31, 2004, 2003 and 2002**

**(In thousands)**

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Cash flows from operating activities: | | | |
| Net income (loss) | $ 46,416 | $ 33,250 | $ (8,799) |
| 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 | 92,353 | 81,927 | 64,513 |
| (Gain) loss on disposal of assets | (282) | (207) | 243 |
| Amortization of deferred revenue | — | — | (3,420) |
| Stock-based compensation | 3,100 | 1,285 | 453 |
| Deferred income taxes | 26,365 | 17,708 | (4,653) |
| Exploration expenditures | 26,730 | 12,810 | 5,909 |
| Non-cash effect of derivative instruments | — | — | 514 |
| Amortization of deferred financing costs | 907 | 902 | 370 |
| Other | 293 | 271 | 52 |
| Changes in operating assets and liabilities, net of acquisition in 2002: | | | |
| Trade accounts receivable | (24,931) | (9,490) | (4,234) |
| Other receivables | (5,600) | — | — |
| Prepaid expenses | (179) | (239) | 154 |
| Other assets | (4,522) | (3,112) | (2,160) |
| Accounts payable and accrued expenses | 6,180 | 4,814 | (21,595) |
| Other liabilities | (1,756) | (949) | (1,930) |
| Net cash provided by operating activities | 165,074 | 136,702 | 25,417 |
| Cash flows used in investing activities: | | | |
| Acquisition of business, net of cash acquired | (2,166) | (850) | (10,661) |
| Property acquisitions | (6,551) | (6,030) | (1,922) |
| Deposit paid on purchase of properties | (5,000) | — | — |
| Exploration and development expenditures | (163,019) | (103,148) | (42,979) |
| Other property and equipment additions | (562) | (608) | (405) |
| Proceeds from sale of oil and gas assets | 585 | 579 | 1,587 |
| Net cash used in investing activities | (176,713) | (110,057) | (54,380) |
| Cash flows from financing activities: | | | |
| Bank overdraft | — | — | (808) |
| Deferred financing costs | (721) | (4,746) | — |
| Repayments of long-term debt | (199) | (118,362) | (15,541) |
| Proceeds from long-term debt | — | 15,000 | 48,000 |
| Proceeds from senior notes offering | — | 150,000 | — |
| Proceeds from public stock offering, net of commissions | 57,378 | 38,000 | — |
| Purchase of shares into treasury | (57,378) | — | — |
| Equity offering costs | (106) | (479) | — |
| Payment of preferred stock dividends | (2,421) | (2,592) | (2,572) |
| Exercise of stock options and warrants | 4,231 | 810 | — |
| Net cash provided by financing activities | 784 | 77,631 | 29,079 |
| Net increase (decrease) in cash and cash equivalents | (10,855) | 104,276 | 116 |
| Cash and cash equivalents at beginning of year | 104,392 | 116 | — |
| Cash and cash equivalents at end of year | $ 93,537 | $ 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 as well as the contiguous onshore gulf coast region. 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. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. Such determination does not exceed one year from completion of drilling. The Company does not currently drill in areas that require major capital expenditures before production can begin. Geological and geophysical costs are charged to expense as incurred.

Leasehold acquisition costs are capitalized. If proved reserves are found on an undeveloped property, leasehold 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 assesses the impairment of capitalized costs of proved oil and natural gas properties when circumstances indicate that the carrying value may not be recoverable. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserve volumes, or other changes to contracts, environmental regulations or tax laws. The calculation is performed on a field-by-field basis, utilizing 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 debt financing are deferred and are 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 conversion of convertible preferred stock shares, the exercise of warrants and stock options and the potential shares associated with restricted share units 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 $1.4 million and $1.7 million at December 31, 2004 and 2003, respectively and had liabilities of $0.5 million at December 31, 2004 and 2003.

### *(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, 2004 and 2003, interest-bearing cash equivalents were approximately $99.9 million and $110.4 million, respectively. Expenditures for exploratory dry holes 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. 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 the forecasted transaction is settled, when the resulting gains and losses will be recorded in earnings. Hedge ineffectiveness is measured at least quarterly based on the changes in fair value between the derivative contract and the hedged item. Any change in fair value resulting from ineffectiveness, will be charged currently to other revenue.

### *(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) permit the continued use of the intrinsic value-based method prescribed by Opinion No. 25, but require 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:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | (In thousands, except per share amounts) | | |
| Net income (loss) available to common stockholders: | | | |
| As reported | $ 43,017 | $ 29,705 | $(12,129) |
| Less: Pro forma stock based employee compensation cost, after tax | 2,179 | 1,002 | 2,565 |
| Pro forma | $ 40,838 | $ 28,703 | $(14,694) |
| Basic earnings (loss) per share: | | | |
| As reported | $ 1.31 | $ 0.96 | $ (0.44) |
| Pro forma | $ 1.24 | $ 0.93 | $ (0.53) |
| Diluted earnings (loss) per share: | | | |
| As reported | $ 1.20 | $ 0.93 | $ (0.44) |
| Pro forma | $ 1.14 | $ 0.91 | $ (0.53) |
| Average fair value of grants during the year | $ 6.19 | $ 4.67 | $ 2.72 |
| Black-Scholes option pricing model assumptions: | | | |
| Risk free interest rate | 4.5% | 4.5% | 4.5% |
| Expected life (years) | 5 | 5 | 5 |
| Volatility | 43.0 to 45.0% | 47.0 to 49.0% | 35.0% |
| Dividend yield | — | — | — |
| Stock-based employee compensation cost, net of tax, included in net income (loss) as reported | $ 340 | $ 28 | $ 257 |

### *(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, 2004 and 2003, the Company had an allowance for doubtful accounts of none and $25,960, 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 uses 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 therefrom disclosed in note 22.

### *(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 2004.

## (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 the Company to register with the SEC for possible public sale 2.5 million shares of common stock. On August 8, 2003 the Company was informed by Evercore that it had priced a public offering of the 2.5 million shares of 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 either of these offerings and did not receive any proceeds from the shares offered by the selling stockholders.

On July 16, 2004 the Company filed a universal shelf registration statement which allows the Company to issue an aggregate of $300 million in common stock, preferred stock, senior debt and subordinated debt in one or more separate offerings with the size, price and terms to be determined at the time of the sale. On November 10, 2004 the Company sold approximately 3.5 million shares of its common stock to the public pursuant to this shelf registration statement leaving us with the ability to issue an additional $239.6 million of securities under the shelf registration statement. Concurrent with this offering, the Company entered into a stock purchase agreement with EIF in which it purchased approximately 3.5 million shares of common stock owned by EIF at a price per share equal to the net proceeds per share received in the offering, before expenses. The Company therefore did not retain any of the proceeds from this offering and the stock has been recorded as treasury stock on the consolidated balance sheet at cost. The Company has no immediate plans to enter into any additional transactions under this registration statement, but plans to use the proceeds for general corporate purposes, which may include debt repayment, acquisitions, expansion and working capital.

## (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 conversion of convertible preferred stock shares, and the exercise of warrants and stock options and the potential shares associated with restricted share units that would have a dilutive effect on earnings per share.

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, 2004 and 2003. 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, 2004: | | | |
| Basic | $43,017 | 32,861 | $1.31 |
| Effect of dilutive securities: | | | |
| Preferred stock | 3,399 | 4,033 | |
| Stock options | — | 638 | |
| Warrants | — | 1,057 | |
| Restricted share units | — | 60 | |
| Diluted | $46,416 | 38,649 | $1.20 |

| | 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 |

## (5) Supplemental Cash Flow Information

The following is supplemental cash flow information:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| | (In thousands) | | |
| Interest paid | $14,323 | $5,877 | $4,616 |
| Income taxes paid, net of refunds | $ 151 | $ 76 | $ (29) |

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| | (In thousands) | | |
| Accretion of preferred stock | $ 978 | $ 953 | $ 758 |
| Conversion of preferred stock | $ 2,368 | $1,418 | $ 145 |
| Exercise of options | $ — | $1,442 | $ — |

## (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 strengthened its management team, expanded its exploration opportunities and achieved a reserve portfolio and production profile that was 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 reflect 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 had a strike price of $9.00 and three million had 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 became exercisable beginning January 15, 2003 and expiring on January 15, 2007. At December 31, 2004 there were 769,651 warrants outstanding with a strike price of $9.00 per share and 2,683,153 warrants outstanding with a strike price of $11.00 per share. 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 from March 3, 2003 until March 1, 2007. The cumulative percentage remitted to the participants was 20% for the March 3, 2003 and 30% for the March 1, 2004 determination dates and is 35% for the March 1, 2005, 40% for the March 1, 2006 and 50% for the March 1, 2007 determination dates. 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 15, 2004 and March 17, 2003, the

Company capitalized, as additional purchase price, and paid additional consideration in cash, of $2.2 million and $0.9 million related to the March 1, 2004 and the March 3, 2003 contingent consideration determination dates, respectively. The Company does not expect the 2005 contingent consideration payment to exceed $1.0 million. Due to the uncertainty inherent in estimating the value of future contingent consideration which includes annual valuations 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 in 2002.

## (7) Property and Equipment

The following is a summary of property and equipment at December 31, 2004 and 2003:

| | 2004 | 2003 |
|---|---|---|
| | (In thousands) | |
| Proved oil and natural gas properties | $750,850 | $584,741 |
| Unproved oil and natural gas properties | 13,275 | 8,716 |
| Other | 5,206 | 4,644 |
| | $769,331 | $598,101 |

We analyze proved properties for impairment based on the proved reserves as determined by our independent reserve engineers. We recognized impairment expense of $6.9 million, $2.8 million and none in the years ending December 31, 2004, 2003 and 2002, respectively. The impairment expenses were related to our East Cameron 378 field in 2004 and our Ship Shoal 133 and West Cameron 149 fields in 2003.

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 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:

| | Year Ended December 31, 2002 |
|---|---|
| | (In thousands, except per share amounts) |
| Net loss available to common stockholders, as reported | $(12,129) |
| Pro forma adjustments to reflect retroactive adoption of Statement 143 | (172) |
| Pro forma net loss | $(12,301) |
| Net loss per share: | |
| Basic — as reported | $ (0.44) |
| Basic — pro forma | $ (0.45) |
| Diluted — as reported | $ (0.44) |
| Diluted — pro forma | $ (0.45) |

The following table reconciles the beginning and ending aggregate recorded amount of the asset retirement obligation for the year ended December 31, 2004:

| | Asset Retirement Obligation |
|---|---|
| | (In thousands) |
| December 31, 2003 | $40,577 |
| Accretion expense | 3,569 |
| Liabilities incurred | 3,686 |
| Liabilities settled | (1,678) |
| Revisions in estimated cash flows | (1,090) |
| December 31, 2004 | $45,064 |

## (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. In January 2005, the remainder of the net proceeds were used to purchase properties in south Louisiana as discussed in note 21.

The Senior Notes mature on August 1, 2010 with interest payable each February 1 and August 1, commencing February 1, 2004. The Company may redeem the notes at its 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, the Company 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 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 August 3, 2004 the Company amended and extended to August 3, 2008 its bank credit facility. Under the amendment the initial borrowing base remained $60 million. The borrowing base was increased to $150 million at the time of our purchase of south Louisiana properties and reserves in January 2005 (see note 21). The borrowing base is subject to redetermination based on the proved reserves of the oil and natural gas properties that serve as collateral for the bank credit facility as set out in the reserve report delivered to the banks each April 1 and October 1. The bank credit facility permits both prime rate based borrowings and London interbank offered rate (LIBOR) borrowings plus a floating spread. The spread will float up or down based on the Company's utilization of the bank credit facility. The spread can range from 1.25% to 2.00% above LIBOR and 0% to 0.75% above prime. The borrowing base under the bank credit facility is secured by substantially all of the assets of the Company. In addition, the Company pays 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 the Company to: (i) maintain a minimum current ratio of 1.0 as defined in the bank credit facility, and (ii) maintain a minimum EBITDAX to interest ratio of 3.5 times. The Company was in compliance with its bank facility covenants as of December 31, 2004.

Total long-term debt outstanding at December 31, 2004 and 2003 was as follows:

| | 2004 | 2003 |
|---|---|---|
| | (In thousands) | |
| Senior Notes, annual interest of 8.75%, payable August 1, 2010 | $150,000 | $150,000 |
| Bank facility, interest rate based on LIBOR borrowing rates plus a floating spread payable August 3, 2008, with weighted average interest commiserate with borrowings outstanding as indicated above | — | 100 |
| Financing note payable, annual interest of 7.99%, equal monthly payments, maturing February 2006 | 217 | 316 |
| | 150,217 | 150,416 |
| Less: Current maturities | 108 | 99 |
| | $150,109 | $150,317 |

Maturities of long-term debt as of December 31, 2004 were as follows (in thousands):

| | |
|---|---|
| 2005 | $ 108 |
| 2006 | 109 |
| 2007 | — |
| 2008 | — |
| 2009 | — |
| Thereafter | 150,000 |
| | $150,217 |

### (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 2004, 23,676.74 shares of Series D Preferred Stock were converted into 277,240 shares of common stock and in 2003, 14,184.9 shares of Series D Preferred Stock were converted into 166,095 shares of common stock.

### (11) Significant Customers

The Company had oil and natural gas sales to three customers accounting for 22 percent, 14 percent and 13 percent, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2004. 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.

## (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 the change in fair value from hedging transactions that are determined to be ineffective are recorded in other revenue, whereas gains and losses from the settlement of hedging contracts are recorded in oil and gas 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.

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, 2004:

**Natural Gas Positions**

| Remaining Contract Term | Contract Type | Strike Price ($/Mmbtu) | Volume (Mmbtu) Daily | Volume (Mmbtu) Total |
|---|---|---|---|---|
| 01/05 - 12/05 | Collar | $ 4.50/$10.75 | 20,000 | 7,300,000 |

**Crude Oil Positions**

| Remaining Contract Term | Contract Type | Strike Price ($/Bbl) | Volume (Bbls) Daily | Volume (Bbls) Total |
|---|---|---|---|---|
| 1/05 - 12/05 | Collar | $31.00/$44.05 | 2,000 | 730,000 |

Subsequent to December 31, 2004, we entered into the following contracts:

**Natural Gas Positions**

| Remaining Contract Term | Contract Type | Strike Price ($/Mmbtu) | Volume (Mmbtu) Daily | Volume (Mmbtu) Total |
|---|---|---|---|---|
| 07/05 - 12/05 | Collar | $ 5.00/$10.00 | 15,000 | 2,760,000 |
| 01/06 - 12/06 | Collar | $ 5.00/$9.51 | 15,000 | 5,475,000 |
| 01/07 - 12/07 | Collar | $ 5.00/$8.00 | 10,000 | 3,650,000 |

For the years ended December 31, 2004, 2003 and 2002, settlements of hedging contracts reduced oil and gas revenues by $15.2, $11.5 and $5.0 million, respectively. The Company has not discontinued hedge accounting treatment in the years presented, and therefore, has not reclassified any gains or losses into earnings as a result.

The following table reconciles the change in accumulated other comprehensive income for the years ended December 31, 2004 and 2003:

| | Year Ended December 31, 2004 | |
|---|---|---|
| | (In thousands) | |
| Accumulated other comprehensive loss as of December 31, 2003 | | $(2,441) |
| Net income | $46,416 | |
| Other comprehensive income — net of tax | | |
| Hedging activities | | |
| Reclassification adjustments for settled contracts — net of taxes of $(5,475) | 9,734 | |
| Changes in fair value of outstanding hedging positions — net of taxes of $4,732 | (8,412) | |
| Total other comprehensive income | 1,322 | 1,322 |
| Comprehensive income | $47,738 | |
| Accumulated other comprehensive loss as of December 31, 2004 — net of taxes of $630 | | $(1,119) |

| | Year Ended December 31, 2003 | |
|---|---|---|
| | (In thousands) | |
| Accumulated other comprehensive loss as of December 31, 2002 | | $(2,171) |
| Net income | $33,250 | |
| Other comprehensive loss — net of tax | | |
| Hedging activities | | |
| Reclassification adjustments for settled contracts — net of taxes of $(4,139) | 7,359 | |
| Changes in fair value of outstanding hedging positions — net of taxes of $4,291 | (7,629) | |
| Total other comprehensive loss | (270) | (270) |
| Comprehensive income | $32,710 | |
| Accumulated other comprehensive loss as of December 31, 2003 — net of taxes of $1,373 | | $(2,441) |

Based upon current prices, the Company expects to transfer approximately $1.7 million of pretax net deferred losses in accumulated other comprehensive income as of December 31, 2004 to earnings during 2005 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, 2004 and 2003. 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.

| | 2004 | | 2003 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| | (In thousands) | | | |
| Financial liabilities: | | | | |
| Current and long-term debt: | | | | |
| The Senior Notes | $150,000 | $163,500 | $150,000 | $156,000 |
| Bank credit facility | — | — | 100 | 100 |
| Financing note payable | 217 | 217 | 316 | 316 |

## (14) Income Taxes

Components of income tax expense (benefit) for the years ended December 31, 2004, 2003 and 2002 are as follows:

| | Current | Deferred | Total |
|---|---|---|---|
| | | (In thousands) | |
| 2004: | | | |
| Federal | $151 | $24,904 | $25,055 |
| State | — | 1,461 | 1,461 |
| | $151 | $26,365 | $26,516 |
| 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) |

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 | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| Expected tax rate | 34.0% | 34.0% | (34.0)% |
| Stock-based compensation | 0.0 | 0.6 | 1.0 |
| State taxes | 2.0 | 2.1 | (1.9) |
| Other | 0.4 | (0.2) | 0.2 |
| | 36.4% | 36.5% | (34.7)% |

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, 2004 and 2003 are presented below:

| | 2004 | 2003 |
|---|---|---|
| | (In thousands) | |
| Current deferred tax assets: | | |
| Fair value of commodity derivative instruments | $ 630 | $ 1,373 |
| Accrued bonus compensation | 1,276 | 1,566 |
| Current deferred tax assets | $ 1,906 | $ 2,939 |
| Deferred tax assets: | | |
| Restricted stock awards and options | $ 1,531 | $ 810 |
| Federal and state net operating loss carryforwards | 15,916 | 18,559 |
| Other | 498 | 439 |
| Deferred tax liability: | | |
| Property, plant and equipment, principally due to differences in depreciation | (71,631) | (49,392) |
| Net non-current deferred tax liability | $(53,686) | $(29,584) |

At December 31, 2004, the Company had net operating loss carryforwards of approximately $44.3 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 at December 31, 2004 and 2003. The 2004 tax provision includes the use of $9.0 million of net operating loss carryforwards.

## (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, restricted share units 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 vested and were 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 per share in April 2003. The grant date fair value of the restricted stock and options was $17.00.

The Company issued restricted stock and restricted share unit awards to employees and officers in the amount of 333,759 in 2004, 131,754 in 2003 and 92,990 in 2002. The restrictions on this stock generally lapse on the first, 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, 2004, 2003 and 2002 was approximately $15.23, $10.12 and $8.19, respectively.

The Company has recognized non-cash compensation expense of $1.8 million, $0.8 million and $0.5 million in 2004, 2003 and 2002, respectively, related to the restricted share and stock option grants. At December 31, 2004, there was $3.4 million of deferred stock based compensation expense related to the restricted share awards, which will be recognized over the remaining vesting periods.

In 2004 and 2003, respectively, 137,000 and 141,500 performance shares were awarded of which 54,167 and 13,333 were forfeited in 2004 and 2003, respectively, leaving 211,000 performance shares outstanding at December 31, 2004. 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 $1.3 million and $0.5 million related to these awards in 2004 and 2003, respectively.

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, 2004, 2003 and 2002 are as follows:

| | 2004 | | 2003 | | 2002 | |
|---|---|---|---|---|---|---|
| | 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 | 2,009,282 | $ 9.68 | 1,997,965 | $ 9.30 | 1,094,282 | $10.76 |
| Granted | 637,000 | $14.01 | 519,200 | $10.18 | 1,110,426 | $ 7.96 |
| Exercised | (453,492) | $ 8.73 | (232,871) | $ 7.98 | — | $ — |
| Forfeited | (160,461) | $11.75 | (275,012) | $ 8.87 | (206,743) | $ 9.85 |
| Outstanding at end of year | 2,032,329 | $11.09 | 2,009,282 | $ 9.68 | 1,997,965 | $ 9.30 |
| Exercisable at end of year | 1,247,964 | $10.78 | 840,027 | $10.13 | 551,349 | $10.16 |
| Available for future grants | 1,508,851 | | 2,584,978 | | 2,869,045 | |

A summary of information regarding stock options outstanding at December 31, 2004 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 | 1,018,496 | 6.5 years | $ 9.08 | 650,764 | $ 8.99 |
| $10.55 - $15.00 | 963,833 | 7.9 years | $12.80 | 597,200 | $12.74 |
| $15.00 - $19.00 | 50,000 | 9.9 years | $18.97 | — | $ — |

The Company also has a 401(k) Plan that covers all employees. The 401(k) 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. By a subsequent amendment in November 2004, the Company match was increased, effective January 1, 2005, to 100% of each individual participant's contribution not to exceed 6% 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 401(k) Plan of 13,210, 15,343 and 9,206 shares of common stock in 2004, 2003 and 2002 valued at approximately $207,000, $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 2006.

Future minimum commitments as of December 31, 2004 under these operating obligations are as follows (in thousands):

| | |
|---|---|
| 2005 | $ 6,441 |
| 2006 | 3,584 |
| 2007 | 1,983 |
| 2008 | 1,972 |
| 2009 | 1,459 |
| Thereafter | 2,015 |
| | $17,454 |

Expense relating to operating obligations for the years ended December 31, 2004, 2003 and 2002 was $6.3 million, $3.7 million and $3.3 million, respectively.

Commencing January 1, 2002, the Company was required to make monthly deposits of $250,000 into a trust for future abandonment costs at East Bay. The Company was not entitled to access the trust fund in order to draw funds for abandonment purposes prior to December 31, 2003. Monthly deposits were not required to be made for fiscal year 2004 and are to resume January 1, 2005. Beginning December 31, 2003 the minimum balance in the trust must be maintained at $6.0 million (with a maximum balance not to exceed $15.0 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

Pursuant to the Company's stockholder agreement with Evercore, the Company paid an affiliate of Evercore a monitoring fee of $250,000 for the years 2003 and 2002. The requirement to pay this fee ceased in November 2003 when Evercore's beneficial ownership of the Company's stock became less than 10% and the stockholder agreement terminated by its terms. 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.

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

The following is a summary of consolidated unaudited interim financial information for the years ended December 31, 2004 and 2003:

| | Three Months Ended | | | |
|---|---|---|---|---|
| | March 31 | June 30 | September 30 | December 31 |
| | (In thousands, except per share data) | | | |
| **2004** | | | | |
| Revenues | $63,472 | $75,067 | $74,117 | $82,554 |
| Costs and expenses | 48,391 | 48,658 | 55,736 | 56,357 |
| Income from operations | 15,081 | 26,409 | 18,381 | 26,197 |
| Net income | 7,446 | 14,656 | 9,569 | 14,745 |
| Net income available to common stockholders | 6,517 | 13,835 | 8,746 | 13,919 |
| Earnings per share: | | | | |
| Basic | $ 0.20 | $ 0.42 | $ 0.27 | $ 0.42 |
| Diluted | 0.20 | 0.38 | 0.25 | 0.37 |
| **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 |

### (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, 2004**

| | Parent Company Only | Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|
| | | (In thousands) | | |
| **ASSETS** | | | | |
| Current assets: | | | | |
| Cash and cash equivalents | $ 93,537 | $ — | $ — | $ 93,537 |
| Accounts receivable | 64,543 | 398 | — | 64,941 |
| Other current assets | 4,191 | — | — | 4,191 |
| Total current assets | 162,271 | 398 | — | 162,669 |
| Property and equipment | 572,809 | 196,522 | — | 769,331 |
| Less accumulated depreciation, depletion and amortization | (224,185) | (80,812) | — | (304,997) |
| Net property and equipment | 348,624 | 115,710 | — | 464,334 |
| Investment in affiliates | 84,165 | — | (84,165) | — |
| Notes receivable, long-term | — | 70,362 | (70,362) | — |
| Other assets | 15,695 | 4,980 | — | 20,675 |
| | $ 610,755 | $191,450 | $(154,527) | $ 647,678 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | | | |
| Current liabilities: | | | | |
| Accounts payable and accrued expenses | $ 80,036 | $ 606 | $ — | $ 80,642 |
| Fair value of commodity derivative instruments | 1,749 | — | — | 1,749 |
| Current maturities of long-term debt | — | 108 | — | 108 |
| Total current liabilities | 81,785 | 714 | — | 82,499 |
| Long-term debt | 150,000 | 70,471 | (70,362) | 150,109 |
| Other liabilities | 63,921 | 36,100 | — | 100,021 |
| | 295,706 | 107,285 | (70,362) | 332,629 |
| Stockholders' equity: | | | | |
| Preferred stock | 33,504 | — | — | 33,504 |
| Common stock | 367 | — | — | 367 |
| Additional paid-in capital | 296,460 | — | — | 296,460 |
| Accumulated other comprehensive loss | (1,119) | — | — | (1,119) |
| Retained earnings | 43,215 | 84,165 | (84,165) | 43,215 |
| Treasury stock | (57,378) | — | — | (57,378) |
| Total stockholders' equity | 315,049 | 84,165 | (84,165) | 315,049 |
| | $ 610,755 | $191,450 | $(154,527) | $ 647,678 |

### Supplemental Condensed Consolidating Statement of Operations
### Year Ended December 31, 2004

| | Parent Company Only | Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|
| | | (In thousands) | | |
| Revenue: | | | | |
| Oil and gas | $226,339 | $68,192 | $ — | $294,531 |
| Other | 26,034 | 378 | (25,733) | 679 |
| | 252,373 | 68,570 | (25,733) | 295,210 |
| Costs and expenses: | | | | |
| Lease operating expenses | 22,820 | 17,797 | — | 40,617 |
| Taxes, other than on earnings | 2,718 | 6,545 | — | 9,263 |
| Exploration expenditures | 34,591 | 1,344 | — | 35,935 |
| Depreciation, depletion and amortization | 76,084 | 16,269 | — | 92,353 |
| General and administrative | 30,070 | 15,904 | (15,000) | 30,974 |
| Total costs and expenses | 166,283 | 57,859 | (15,000) | 209,142 |
| Income from operations | 86,090 | 10,711 | (10,733) | 86,068 |
| Interest expense, net | (13,158) | 22 | — | (13,136) |
| Income before income taxes | 72,932 | 10,733 | (10,733) | 72,932 |
| Income taxes | (26,516) | — | — | (26,516) |
| Net income | $ 46,416 | $10,733 | $(10,733) | $ 46,416 |

### Supplemental Condensed Consolidating Statement of Cash Flows
### Year Ended December 31, 2004

| | Parent Company Only | Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|
| | | (In thousands) | | |
| Net cash provided by operating activities | $141,906 | $24,530 | $(1,362) | $165,074 |
| Cash flows used in investing activities: | | | | |
| Acquisition of business, net of cash acquired | (2,166) | — | — | (2,166) |
| Property acquisitions | (4,025) | (2,526) | — | (6,551) |
| Deposit paid on purchase of properties | — | (5,000) | — | (5,000) |
| Exploration and development expenditures | (147,476) | (15,543) | — | (163,019) |
| Other property and equipment additions | (562) | — | — | (562) |
| Proceeds from the sale of oil and natural gas assets | 585 | — | — | 585 |
| Net cash used in investing activities | (153,644) | (23,069) | — | (176,713) |
| Cash flows provided by (used in) financing activities: | | | | |
| Deferred financing costs | (721) | — | — | (721) |
| Repayments of long-term debt | (100) | (1,461) | 1,362 | (199) |
| Equity offering costs | (106) | — | — | (106) |
| Proceeds from public offering net of commissions | 57,378 | — | — | 57,378 |
| Purchase of shares into treasury | (57,378) | — | — | (57,378) |
| Dividends paid | (2,421) | — | — | (2,421) |
| Exercise of stock options and warrants | 4,231 | — | — | 4,231 |
| Net cash provided by (used in) financing activities | 883 | (1,461) | 1,362 | 784 |
| Net decrease in cash and cash equivalents | (10,855) | — | — | (10,855) |
| Cash and cash equivalents at the beginning of the period | 104,392 | — | — | 104,392 |
| Cash and cash equivalents at the end of the period | $ 93,537 | $ — | $ — | $ 93,537 |

## (20) New Accounting Pronouncements

In November 2004, the FASB issued Statement of Financial Accounting Standards No. 151 "Inventory Costs, an amendment of ARB No. 43, Chapter 4" ("Statement 151"). The amendments made by Statement 151 clarify that abnormal amounts of idle facility expense, freight, handling costs, and wasted materials (spoilage) should be recognized as current-period charges and require the allocation of fixed production overheads to inventory based on the normal capacity of the production facilities. The guidance is effective for inventory costs incurred during fiscal years beginning after June 15, 2005. Earlier application is permitted for inventory costs incurred during fiscal years beginning after November 23, 2004. The Company's assessment of the provisions of Statement 151 is that it is not expected to have an impact on the financial position, results of operations or cash flows of the Company.

In December 2004, the FASB issued Statement of Financial Accounting Standards No. 152 "Accounting for Real Estate Time-Sharing Transactions — An Amendment to FASB Statements No. 66 and 67" ("Statement No. 152"). Statement 152 amends FASB Statement No. 66, "Accounting for Sales of Real Estate," to reference the financial accounting and reporting guidance for real estate time-sharing transactions that is provided in AICPA Statement of Position (SOP) 04-2, "Accounting for Real Estate Time-Sharing Transactions." Statement 152 also amends FASB Statement No. 67, "Accounting for Costs and Initial Rental Operations of Real Estate Projects," to state that the guidance for (a) incidental operations and (b) costs incurred to sell real estate projects does not apply to real estate time-sharing transactions. The accounting for those operations and costs is subject to the guidance in SOP 04-2. Statement 152 is effective for financial statements for fiscal years beginning after June 15, 2005. The Company's assessment of the provisions of Statement 152 is that it is not expected to have an impact on the financial position, results of operations or cash flows of the Company.

In December 2004, the FASB issued Statement of Financial Accounting Standards No. 153 "Exchanges of Non-monetary assets — an amendment of APB Opinion No. 29" ("Statement 153"). Statement 153 amends Accounting Principles Board (APB) Opinion 29 to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. Statement 153 does not apply to a pooling of assets in a joint undertaking intended to fund, develop, or produce oil or natural gas from a particular property or group of properties. The provisions of Statement 153 shall be effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. Early adoption is permitted and the provisions of Statement 153 should be applied prospectively. The Company's assessment of the provisions of Statement 153 is that it is not expected to have an impact on the financial position, results of operations or cash flows of the Company.

In December 2004, the FASB issued Statement of Financial Accounting Standards No. 123-Revised 2004, "Share-Based Payment," ("Statement 123R"). This is a revision of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation", and supersedes APB No. 25, "Accounting for Stock Issued to Employees." The Company currently accounts for stock-based compensation under the provisions of APB No. 25. Under Statement 123R, the Company will be required to measure the cost of employee services received in exchange for stock based on the grant-date fair value (with limited exceptions). That cost will be recognized as expense over the period during which an employee is required to provide service in exchange for the award (usually the vesting period). The fair value will be estimated using an option-pricing model. Excess tax benefits, as defined in Statement 123R, will be recognized as an addition to paid-in capital. This is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. The Company is currently in the process of evaluating the impact of Statement 123R on its financial statements, including different option-pricing models. Note (2)(j) illustrates the current effect on net income and earnings per share if the Company had applied the fair value recognition provisions of Statement 123.

**(21) Subsequent Events — (Unaudited)**

On January 20, 2005, the Company closed an acquisition of properties and reserves in south Louisiana for \$146.0 million in cash, after adjustments for the exercise of preferential rights by third parties and preliminary closing adjustments. The acquisition is composed of nine fields, four of which were producing at the time of the closing through 14 wells, with estimated proved reserves of 51.2 Bcfe. Also included were interests in 22 exploratory prospects. The transaction expands the Company's exploration opportunities in its expanded focus area and further reduces the concentration of its reserves and production. Upon the signing of the purchase agreement, the Company paid a \$5.0 million deposit in 2004 toward the purchase price which is recorded as other assets in the consolidated balance sheet, and concurrent with the closing, the borrowing base under the Company's bank credit facility was increased to provide for a \$150 million borrowing base of which \$60 million was drawn to fund the acquisition. In connection with the acquisition, the Company has also entered into a two-year agreement with the seller of the properties that defines an area of mutual interest ("AMI") encompassing over one million acres. The Company intends to continue to explore and develop oil and gas reserves in the AMI over the next two years jointly with the seller. The proved reserves, prospects and the AMI are in the southern portions of Terrebone, Lafourche and Jefferson Parishes in Louisiana. The Company does not have enough information at this time to prepare the purchase price allocation, however, it believes that the entire purchase price will be allocated to oil and natural gas assets and asset retirement obligation. The results of operations of the acquired properties will be included in the Company's 2005 consolidated statement of operations following the closing date of January 20, 2005.

On March 8, 2005, the Company closed the acquisition of the remaining 50% gross working interest in South Timbalier 26, above approximately 13,000 feet subsea that it did not already own, from Apache Corporation for approximately \$21.0 million after preliminary closing adjustments from the effective date of December 1, 2004. As a result of the acquisition, the Company now owns a 100% gross working interest in this field. The acquisition expands the Company's interest in its core Greater Bay Marchand area and gives the Company additional flexibility in undertaking the future development of the South Timbalier 26 field. The Company does not have enough information at this time to prepare the purchase price allocation, however, it believes that the entire purchase price will be allocated to oil and natural gas assets and asset retirement obligation. The results of operations of the additional interest acquired will be included in the Company's 2005 consolidated statement of operations for periods following the closing of the acquisition.

On February 28, 2005, the Company gave notice of the redemption of all of the Series D Preferred Stock issued in connection with the HHOC acquisition (notes 6 and 10) that remain outstanding on the redemption date of March 21, 2005. The redemption price is \$100 per share plus accrued and unpaid dividends to the redemption date, which are estimated to be \$1.75 per share. Holders of record have the right to convert their shares into shares of common stock through the close of business on March 18, 2005. As of February 28, 2005, 115,100.11 shares of Series D Preferred Stock remained outstanding convertible into a total of 1,347,776 shares of common stock.

**(22) Supplementary Oil and Natural Gas Disclosures — (Unaudited)**

Our December 31, 2004, 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. 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, 2001 | 25,462 | 61,797 |
| Purchase 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 | (2,912) | (28,688) |
| December 31, 2003 | 27,414 | 134,404 |
| Extensions, discoveries and other additions | 3,231 | 67,049 |
| Revisions | 1,296 | (21,570) |
| Production | (3,171) | (30,048) |
| December 31, 2004 | 28,770 | 149,835 |
| Proved-developed reserves: | | |
| December 31, 2002 | 21,070 | 70,014 |
| December 31, 2003 | 22,306 | 71,531 |
| December 31, 2004 | 24,737 | 102,760 |

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

| | 2004 | 2003 |
|---|---|---|
| | (In thousands) | |
| Proved properties | $ 750,850 | $ 584,741 |
| Unproved properties | 13,275 | 8,716 |
| Accumulated depreciation, depletion and amortization | (301,639) | (207,237) |
| Net capitalized costs | $ 462,486 | $ 386,220 |

Costs incurred for oil and natural gas property acquisition, exploration and development activities for the years ended December 31, 2004, 2003 and 2002 are as follows:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| | (In thousands) | | |
| Business combinations | | | |
| Proved properties | $ 2,166 | $ 850 | $116,415 |
| Unproved properties | — | — | 7,616 |
| Total business combinations | 2,166 | 850 | 124,031 |
| Lease acquisitions | 6,551 | 6,030 | 1,922 |
| Exploration | 113,278 | 60,170 | 27,083 |
| Development | 72,235 | 45,682 | 39,061 |
| Asset retirement liabilities incurred | 3,686 | 812 | — |
| Asset retirement revisions | (189) | 2,519 | — |
| Costs incurred | $197,727 | $116,063 | $192,097 |

**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:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | | (In thousands) | |
| Future cash inflows | $2,136,571 | $1,672,895 | $1,392,062 |
| Future production costs | (570,552) | (441,042) | (355,131) |
| Future development and abandonment costs | (294,936) | (264,404) | (220,946) |
| Future income tax expense | (358,421) | (245,934) | (183,377) |
| Future net cash flows after income taxes | 912,662 | 721,515 | 632,608 |
| 10% annual discount for estimated timing of cash flows | (244,994) | (192,100) | (155,707) |
| Standardized measure of discounted future net cash flows | $ 667,668 | $ 529,415 | $ 476,901 |

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, 2004, 2003 and 2002 is as follows:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | | (In thousands) | |
| Beginning of the period | $ 529,415 | $ 476,901 | $ 123,377 |
| Sales and transfers of oil and natural gas produced, net of production costs | (247,007) | (185,360) | (93,174) |
| Net changes in prices and production costs | 140,169 | 59,988 | 247,642 |
| Extensions, discoveries and improved recoveries, net of future production costs | 270,223 | 149,459 | 131,796 |
| Revision of quantity estimates | (50,384) | 18,380 | 9,927 |
| Previously estimated development costs incurred during the period | 55,893 | 21,379 | 32,189 |
| Purchase and sales of reserves in place | — | — | 179,772 |
| Changes in estimated future development costs | (7,300) | (15,851) | (19,403) |
| Changes in production rates (timing) and other | (8,819) | (37,680) | (22,510) |
| Accretion of discount | 70,124 | 60,827 | 12,912 |
| Net change in income taxes | (84,646) | (18,628) | (125,627) |
| Net increase | 138,523 | 52,514 | 353,524 |
| End of period | $ 667,668 | $ 529,415 | $ 476,901 |

The December 31, 2004 computation was based on period-end prices of $6.23 per Mcf for natural gas and $41.84 per barrel for crude oil. 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. Spot prices as of February 25, 2005 were $6.33 per Mmbtu for natural gas and $48.25 per barrel for crude oil before adjustment for lease quality, transportation fees and price differentials.

Schedule II

## VALUATION AND QUALIFYING ACCOUNTS

| | Balance at the Beginning of the Year | Additions Charged to Costs and Expenses | Deductions | Balance at the End of the Year |
|---|---|---|---|---|
| | | (In thousands) | | |
| Allowance for doubtful accounts: | | | | |
| 2002 | 272 | 7 | — | 279 |
| 2003 | 279 | — | 253 | 26 |
| 2004 | 26 | — | 26 | — |

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

None.

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

**Conclusion Regarding the Effectiveness of Disclosure 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. There was no change in our internal control over financial reporting during the fiscal quarter ended December 31, 2004 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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. See Management's Report on Internal Control Over Financial Reporting and the Report of Independent Registered Public Accounting Firm — Internal Control Over Financial Reporting, which are included herein.

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

None.

## 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 12, 2005, 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 which is available 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 12, 2005, 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 12, 2005, 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, 2004, with respect to compensation plans under which our equity securities are authorized for issuance.

| | Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights(1) | Weighted Average Exercise Price of Outstanding Options(2) | Number of Securities Remaining Available for Future Grant Under Equity Compensation Plans |
|---|---|---|---|
| Equity compensation plans approved by stockholders .... | 1,707,494 | $10.78 | 1,508,851 |
| Equity compensation plans not approved by stockholders .... | — | — | — |

(1) Comprised of 1,247,964 shares subject to issuance upon the exercise of options, 211,000 shares issued as performance shares and 248,530 shares to be issued upon the lapsing of restrictions associated with restricted share units

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

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 12, 2005, 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 12, 2005, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

## PART IV

**Item 15.** ***Exhibits and Financial Statement Schedules***

(a) *Documents to be filed as part of this Report:*

1. *Financial Statements:*

The following financial statements are included in this Report on Form 10-K:

Management's Report on Internal Control Over Financial Reporting

Report of Independent Registered Public Accounting Firm — Internal Control Over Financial Reporting

Report of Independent Registered Public Accounting Firm — Consolidated Financial Statements

Consolidated Balance Sheets as of December 31, 2004 and 2003

Consolidated Statements of Operations for the years ended December 31, 2004, 2003 and 2002

Consolidated Statements of Changes in Stockholders' Equity for the years ended December 31, 2004, 2003 and 2002

Consolidated Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002

Notes to the Consolidated Financial Statements

2. *Financial Statement Schedules:*

Schedule II — Valuation and Qualifying Accounts.

(b) *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 Form 8-K filed April 3, 2003 (File No. 333-42876)). |
| 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)). |
| 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 | — Fourth Amended and Restated 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 JPMorgan Chase Bank, dated as of August 3, 2004 (incorporated by reference to Exhibit 10.1 of EPL's Form 10-Q filed August 5, 2004). |

| Exhibit Number | Title |
|---|---|
| 10.5 | — 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)). |
| 10.6 | — 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). |
| 10.7 | — 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). |
| 10.8 | — Second Amendment to Earnout Agreement between Energy Partners, Ltd. and Participants effective January 1, 2003 (incorporated by reference to Exhibit 10.12 to EPL's Form 10-K filed March 9, 2004). |
| 10.9 | — Purchase and Sale Agreement, dated as of December 16, 2004, between Castex Energy 1995, L.P., Castex Energy, Inc., the Company and EPL of Louisiana, L.L.C. (incorporated by reference to Exhibit 10.1 to the Company's Form 8-K dated December 16, 2004). |
| 10.10 | — Exploration Agreement, dated as of December 16, 2004, between Castex Energy 1995, L.P., Castex Energy, Inc., the Company and EPL of Louisiana, L.L.C. (incorporated by reference to Exhibit 10.2 to the Company's Form 8-K dated December 16, 2004). |
| 10.11 | — Offer Letter of Mr. Phillip A. Gobe, dated October 19, 2004 (incorporated by reference to Exhibit 10.1 of the Company's Form 8-K filed October 25, 2004. |
| 10.12 | — Offer Letter of Mr. David R. Looney, dated February 9, 2005 (incorporated by reference to Exhibit 10.1 of the Company's Form 8-K filed February 14, 2005). |
| 10.13 | — First Amendment to Energy Partners, Ltd. Amended and Restated 2000 Long Term Stock Incentive Plan (incorporated by reference to Exhibit 10.2 of EPL's Form 10-Q filed August 5, 2004). |
| 10.14 | — Form of Nonqualified Stock Option Grant under the Energy Partners, Ltd. Amended and Restated 2000 Long Term Stock Incentive Plan (incorporated by reference to Exhibit 10.3 of EPL's Form 10-Q filed August 5, 2004). |
| 10.15 | — Form of Restricted Share Unit Agreement under the Energy Partners, Ltd. Amended and Restated 2000 Long Term Stock Incentive Plan (incorporated by reference to Exhibit 10.4 of EPL's Form 10-Q filed August 5, 2004). |
| 10.16 | — Form of Stock Option Grant under the Energy Partners, Ltd. 2000 Stock Option Plan for Non-employee Directors (incorporated by reference to Exhibit 10.5 of EPL's Form 10-Q filed August 5, 2004). |
| 10.17* | — Energy Partners, Ltd. Key Employee Retention Plan, effective as of April 15, 2003. |
| 10.18* | — Summary of the Compensation of Non-Employee Directors of Energy Partners, Ltd. |
| 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 14, 2005. |
| 99.2* | — Report of Independent Petroleum Engineers dated as of February 14, 2005. |

* 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 13, 2005 |
| /s/ SUZANNE V. BAER<br>Suzanne V. Baer | Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer) | March 13, 2005 |
| /s/ JOHN C. BUMGARNER, JR.<br>John C. Bumgarner, Jr. | Director | March 13, 2005 |
| /s/ JERRY D. CARLISLE<br>Jerry D. Carlisle | Director | March 13, 2005 |
| /s/ HAROLD D. CARTER<br>Harold D. Carter | Director | March 13, 2005 |
| /s/ ENOCH L. DAWKINS<br>Enoch L. Dawkins | Director | March 13, 2005 |
| /s/ ROBERT D. GERSHEN<br>Robert D. Gershen | Director | March 13, 2005 |
| /s/ WILLIAM O. HILTZ<br>William O. Hiltz | Director | March 13, 2005 |
| /s/ EAMON M. KELLY<br>Eamon M. Kelly | Director | March 13, 2005 |
| /s/ JOHN G. PHILLIPS<br>John G. Phillips | Director | March 13, 2005 |

# ENERGY PARTNERS LTD

**BOARD OF DIRECTORS**

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

John C. Bumgarner
Managing Member
Utica Plaza, LLC

Jerry D. Carlisle
Independent investor

Harold D. Carter
Independent oil and
gas consultant

Enoch L. Dawkins
Retired President
Murphy Exploration and
Production Company

Robert D. Gershen
President
Associated Energy Managers, LLC

William O. Hiltz
Senior Managing Director
Evercore Partners

John G. Phillips
Retired Chairman, President
and Chief Executive Officer
The Louisiana Land and
Exploration Company

**OFFICERS**

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

Phillip A. Gobe
Executive Vice President
and Chief Operating Officer

David R. Looney
Executive Vice President and Chief
Financial Officer

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

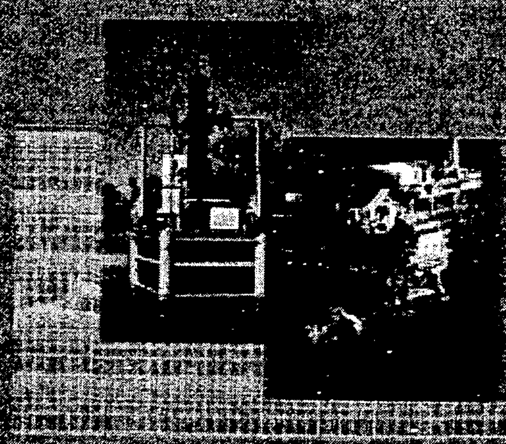
T. Rodney Dykes
Senior Vice President - Production

William Flores
Senior Vice President - Drilling

L. Keith Vincent
Vice President - Land

Kenneth R. Sanders
Treasurer

* Succeeded Suzanne V. Baer as the Company's Executive Vice President and Chief Financial Officer in March 2005



**CORPORATE INFORMATION**

Corporate Office
201 St. Charles Ave.
Suite 3400
New Orleans, LA 70170
504.569.1875
www.epl[illegible].com

Houston Office
700 Louisiana St., Suite [illegible]
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 S[illegible]
will be held in New [illegible]
May 12, 2005 [illegible]

Stock Exchange Listing
New York Stock Exchange
Symbol: EPL

Investor Information
Information on the Company [illegible]
ing this annual report, Form [illegible]
news releases, latest [illegible]
to [illegible] quarterly [illegible]
reporting are availab[illegible]
site at www.eplweb.com [illegible]
parties may also contact [illegible]
investor relations [illegible]
504.569.1875

**CERTIFICATION STATEMENT**

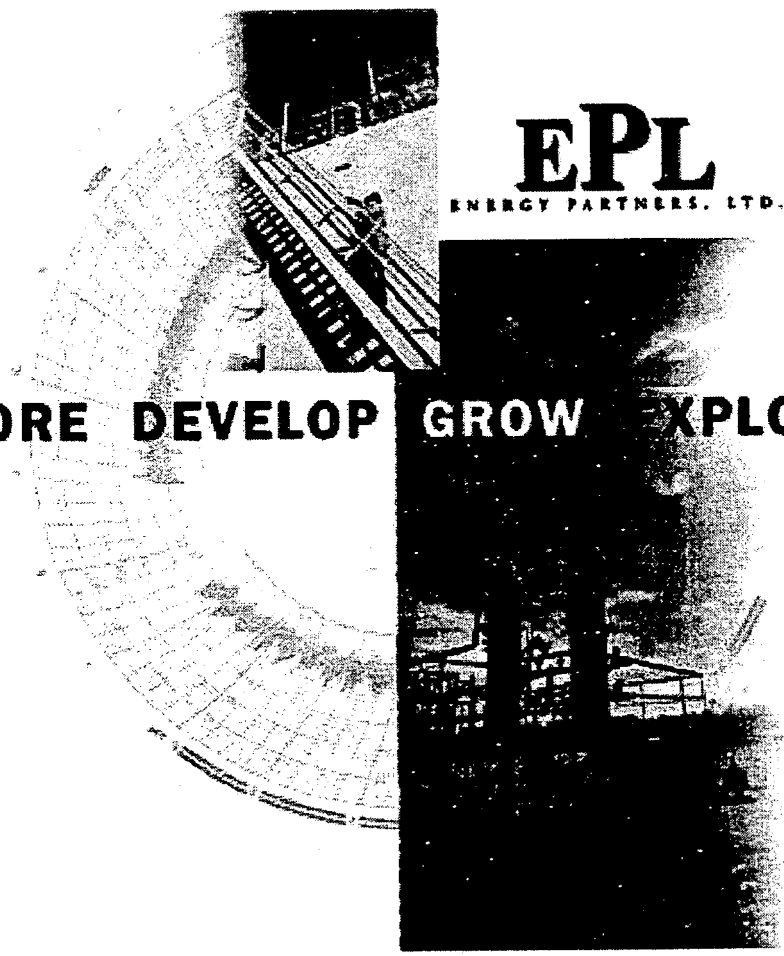
The New York Stock Exchange [illegible]
303A.12(a) requires chief [illegible]
officers of listed corporations [illegible]
certify that they are not aware [illegible]
violations by their company [illegible]
exchange's corporate [illegible]
standards. The annual [illegible]
the Chief Executive Officer [illegible]
Partners, Ltd. has been [illegible]
New York Stock Exchange [illegible]

**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.



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