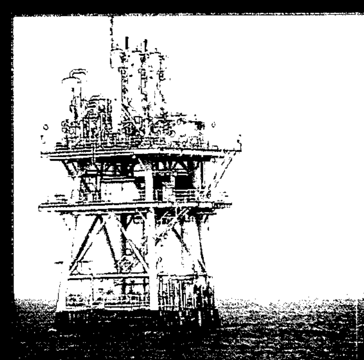
2001 ANNUAL REPORT

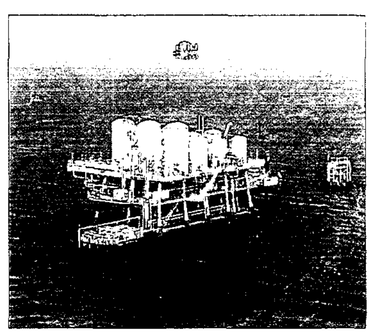
BUILDING STRENGTH

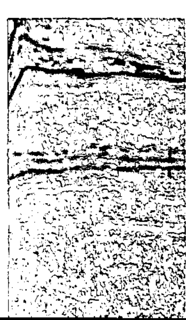


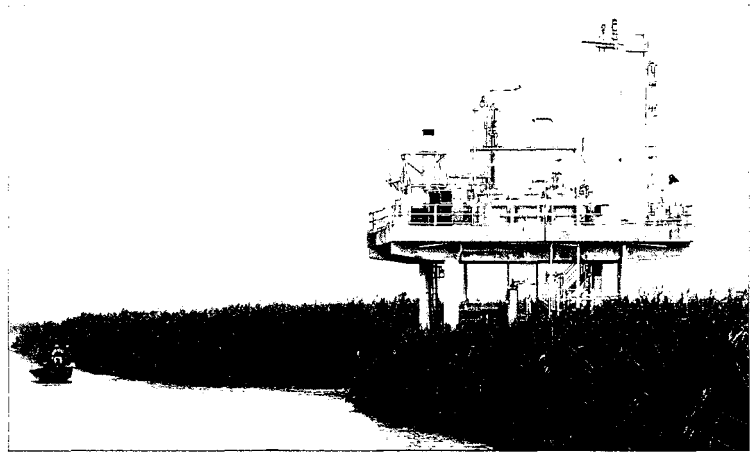
BUILDING STRENGTH

WE SELECTED THIS THEME FOR OUR 2001 ANNUAL REPORT TO DESCRIBE THE TANGIBLE STEPS WE HAVE TAKEN TO REINFORCE THE STRONG FOUNDATION WE HAVE BUILT AT EPL THAT IS CENTERED AROUND OUR PEOPLE, PROPERTIES AND UNIQUE VALUE-CREATION STRATEGY.

Energy Partners, Ltd., founded in 1998, is an independent exploration and production company concentrated in the shallow to moderate depth waters of the central region of the Gulf of Mexico Shelf. We have focused on this area because it provides us with favorable geologic and economic conditions, including multiple reservoir formations, regional economies of scale, extensive infrastructure and comprehensive databases. We believe this region offers a balanced and ample array of exploitation, development and exploration opportunities that enable us to achieve attractive rates of return on our invested capital.







The exploration and production sector of our industry learned long ago to accept volatility in commodity prices and energy demand as the status quo. However, in my 30 plus years of experience in the energy industry, I don't believe any year can quite compare to 2001 for its unprecedented extremes.

We began the year with record high natural gas prices of $9.82 per Mmbtu and strong crude oil prices of $32.19 per Bbl. Industry experts declared the North American natural gas bubble permanently burst and OPEC firmly in control of world oil prices. E&P companies reported record profits while oil field service costs rose rapidly in anticipation of a sustained record level of drilling activity.

Within a few short months, we were again reminded that conventional wisdom can be quickly overruled by the laws of supply and demand. A significant downturn in economic activity, unseasonably mild weather across the U.S. in the summer, fall and early winter, along with threats to our national security all contributed to a sharp decline in energy demand and commodity prices. Oil field service costs fell as drilling activity came to a virtual standstill. By year-end, natural gas prices fell to 30-month lows of $1.83 per Mmbtu and crude oil prices declined to $17.45 per Bbl.

Despite this confluence of negative factors, I am pleased that the EPL 2001 report card shows significant progress in value creation, both financially and operationally. Moreover, we also made significant progress in the execution of our long-term strategy. We are especially proud of the efforts expended by all of our employees that contributed to last year's success.

The highlights for the year include:

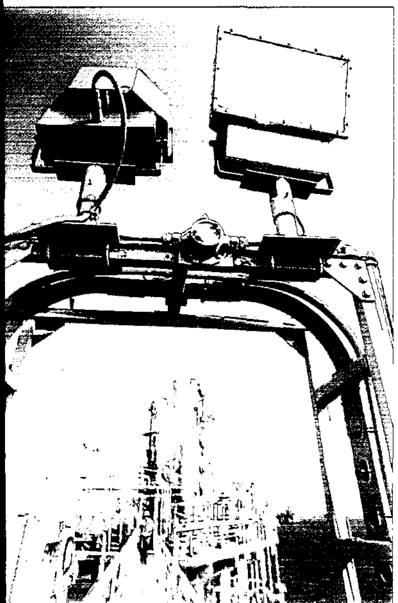
- Generating record revenue, net income and cash flow from operations.
- Attaining a 19% return on average capital employed.
- Replacing 128% of full year production through successful drilling.
- Achieving an 86% success rate on well projects.
- Increasing production 57% to 16,118 Boe per day, a new record high.
- Expanding our property portfolio with our East Cameron 9 exploratory success.
- Negotiating the Hall-Houston acquisition.

From a financial standpoint, for the year 2001, we reported revenues of $145.9 million, up 42% from $103.1 million in 2000. Net income for 2001 totaled $12 million, or $0.44 per diluted share versus a net loss of $18.7 million, or $2.27 per diluted share, including one-time charges and gains, in 2000. Discretionary cash flow increased 51% to $84 million from $55.7 million in 2000 and we attained a 19% return on average capital employed in 2001.

From an operational standpoint, we replaced 128% of 2001 production through the drill-bit. After considering negative reserve revisions due mainly to lower year-end prices, we still replaced 101% of production. During 2001, we completed only one nominal acquisition and had no dispositions of reserves. Since the Hall-Houston acquisition was not completed until after year-end, none of the reserves acquired are included in our 2001 reserves. Our ongoing well operations program achieved an 86% success rate, consistent with our cumulative success rate on well projects since inception of 88%. This successful program was largely responsible for a 57% increase in our total production to 16,118 Boe per day in 2001 compared with 10,252 Boe per day in 2000.

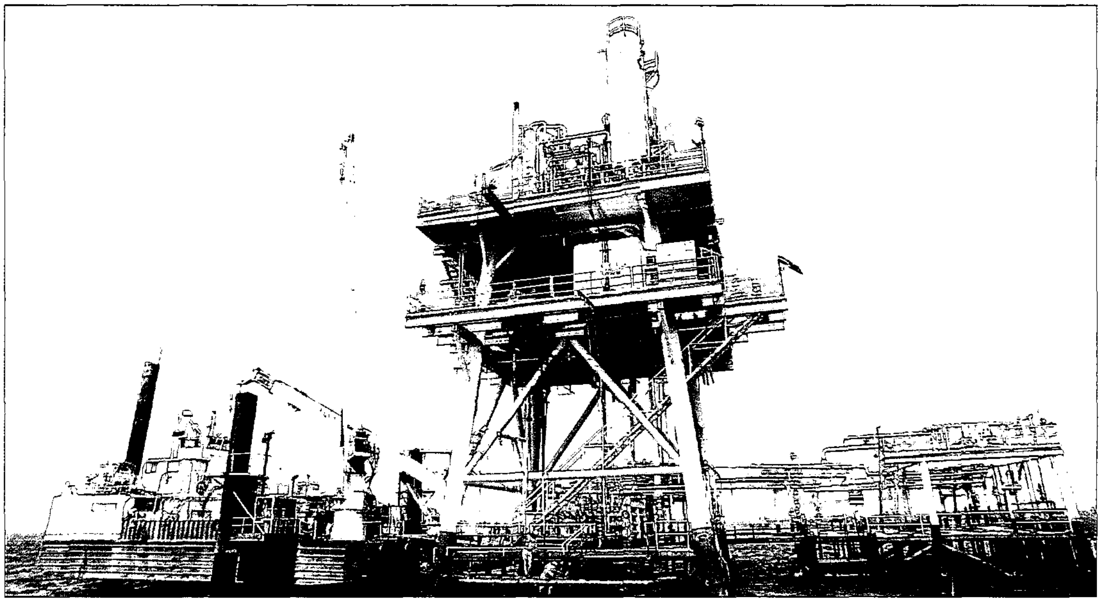
We invested a total of $104 million in 2001 which included 59 successful workovers and recompletions and 17 new drill wells. We invested about 13% less than we had initially budgeted in response to lower commodity prices and our partners' curtailment of drilling operations in the second half of the year. Since our inception, we have invested $292 million net on well projects and strategic property acquisitions resulting in an average cost of adding new reserves of $6.34 per Boe, a competitive replacement cost for a Gulf of Mexico focused producer.

Our most notable drilling success in 2001 was our exploratory well at East Cameron 9. The well encountered 111 feet of potential natural gas pay in eight sands and tested approximately 8 Mmcf per day gross in a limited production test. Production facilities are under construction. We are currently evaluating the results of the well to determine the number and location of future development wells. EPL operates and owns a 50% working interest in this exciting new addition to our property portfolio.



While these financial and operational highlights were significant, I think our most important accomplishment during 2001 was the successful negotiation of the acquisition of Hall-Houston Oil Company. As discussed in greater detail later in this report, we believe this acquisition adds significant strengths, in terms of assets, prospects, technical skills and management. We were especially attracted to Hall-Houston's exploratory drilling track record, as well as their technical and managerial talents which complement our own. We welcome their senior management, Gary Hall, Bruce Sidner and John Peper, to the EPL team. We have already integrated our two teams and believe you will be very pleased with the results we will achieve as a stronger, more balanced company. We fully preserved our financial flexibility and retained our strong balance sheet following the January 15, 2002 closing of the transaction with our estimated debt to total capitalization ratio rising to only 30%.

Looking ahead to 2002, we have taken a very flexible approach to establishing our capital budget for this year, which we currently estimate will be in the range of $60 to $80 million. This flexible budget is due in part to uncertainty in the direction of commodity prices, and more importantly, because we believe the current industry environment will offer us many opportunities to expand our portfolio of properties. We will look equally at our internally generated drilling prospects, potential new drill-to-earn arrangements and strategic property acquisitions in our focus area as all serving as attractive ways to grow the company and increase our return on capital employed. In all cases, we intend to limit our spending to internally generated cash flow and maintain the strong balance sheet that has been the hallmark of EPL.



Your management team continues to own a substantial ownership stake in EPL. This large position provides clear assurance to you, our shareholders, that our interests are, indeed, very closely aligned. While we were pleased with our accomplishments last year, we were very disappointed with the performance of our common stock. We believe we added value for all of our shareholders last year. Unfortunately, we don't believe the performance of our common stock reflects that value accretion. A number of external market and industry factors no doubt played a significant role in the decline in our stock price; nonetheless, the market clearly indicated that it expected more from us.

While we cannot control those external factors, I am confident that the strengths we have added have substantially reinforced our already strong foundation. Now, more than ever before, we have the right team, the right properties and the right strategy to grow our company and achieve superior results. We believe the continued successful execution of our strategy will ultimately result in the market rewarding us with a premium valuation. We sincerely appreciate your ongoing support of your management team.

Richard A. Bachmann

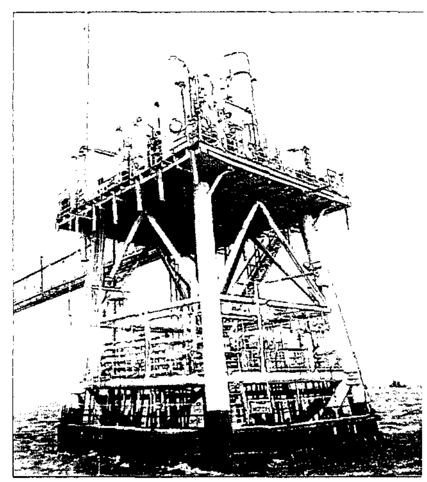
Chairman, President and Chief Executive Officer

FINANCIAL DATA

(In thousands, except per share amounts)	2001	2000	1999	1998 (a)
Revenues	$ 145,927	$ 103,072	$ 9,509	$ 1,966
EBITDAX (b)	82,635	58,853	5,260	992
Income (loss) from operations (c)	20,624	(8,721)	(835)	(311)
Net income (loss)	11,974	(18,684)	(2,284)	(705)
Diluted earnings (loss) per common share (d)	$ 0.44	$ (2.27)	$ (0.22)	$ (0.09)
Diluted weighted average common shares	26,920	11,160	14,247	7,427
Cash flows from operating activities	91,847	50,703	(4,594)	8,044
Capital and exploration expenditures	122,340	165,360	19,233	27,081
Total assets	$ 242,777	$ 208,149	$ 69,276	$ 40,015
Long-term debt	25,493	100	10,150	20,000
Redeemable preferred stock	–	–	56,475	–
Stockholders' equity	164,867	150,591	(3,815)	(694)

OPERATING DATA

	2001	2000	1999	1998 (a)
Total estimated net proved reserves:				
Oil (Mbbls)	25,462	27,521	3,824	2,861
Natural gas (Mmcf)	61,797	49,150	12,752	12,534
Total (Mboe)	35,762	35,712	5,949	4,950
Net production (per day):				
Oil (Bbls)	10,358	7,622	1,051	534
Natural gas (Mcf)	34,562	15,781	2,277	1,311
Total (Boe)	16,118	10,252	1,431	753
Average sales price:				
Oil (per Bbl)	$ 23.39	$ 25.80	$ 17.39	$ 13.21
Natural gas (per Mcf)	4.40	4.98	2.17	2.20
Total (per Boe)	24.45	26.84	16.22	13.18
Present value of estimated future net revenues before income taxes (in thousands)(e)	$ 129,122	$ 489,945	$ 54,819	$ 27,533
Total well projects	88	108	20	10
Percentage of successful well projects	86%	91%	75%	100%



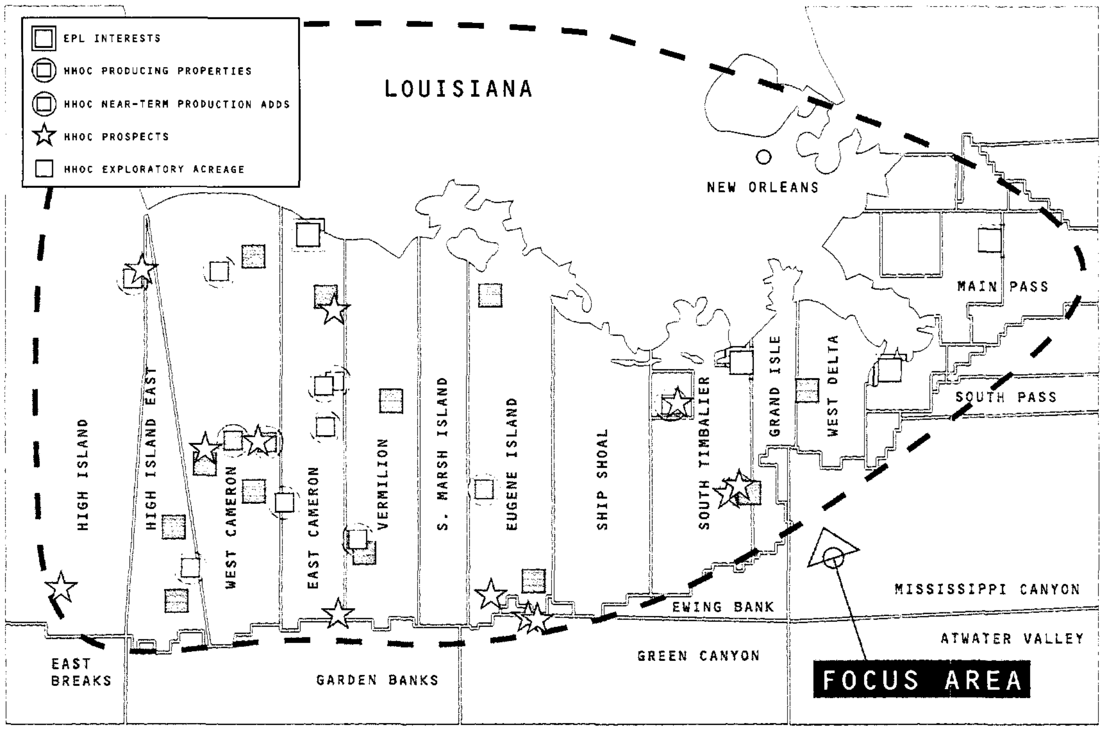
(a) We were incorporated on January 29, 1998.

(b) Earnings before interest, taxes, depreciation, depletion and amortization, exploration expense and the non-cash stock compensation charge of $40.3 million in 2000.

(c) 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.

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

(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.



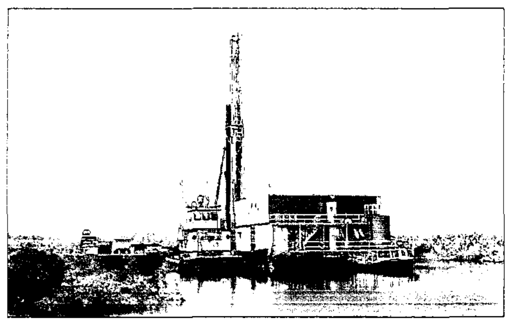
FOCUSED ON PROFITABLE GROWTH

Our primary goal at EPL is to achieve a rate of return on the capital we employ that is significantly higher than that of our industry peers. We believe we have made good progress toward that goal, achieving average returns of 31%, and 19% in 2000 and 2001, respectively.

Our strategy was carefully devised to build an E&P company that would create value and achieve those higher rates of return in any commodity price environment. We have focused on the Gulf of Mexico Shelf because of the large number of opportunities it provides us to achieve our goals. This area offers favorable geologic and economic conditions, including multiple reservoir formations, regional economies of scale, extensive infrastructure and comprehensive geologic databases. The region provides an excellent array of exploitation, development and exploration opportunities.

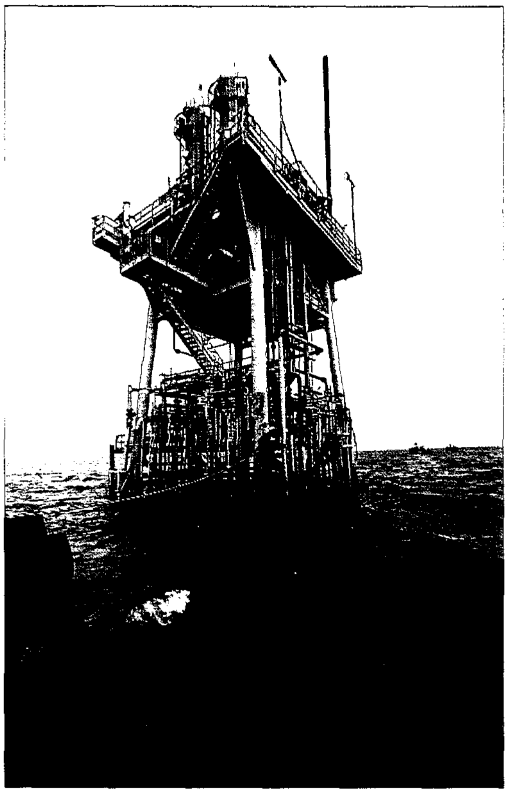
We have successfully used a combination of internally generated drilling opportunities, multi-year, multi-well drill-to-earn programs, and strategic acquisitions to grow EPL. In 2001, we took a major step forward in advancing the execution of our strategy with the acquisition of Hall-Houston Oil Company, whose management shared a similar vision of building a highly profitable and efficient aggregator of properties in the same focus area. The map above highlights the producing properties, exploratory prospects and prospective acreage HHOC adds to our existing producing property portfolio.

Last year, our operational achievements included continued strong results in our drilling and workover program, a substantial rise in production volumes and a significant exploratory success at East Cameron 9. These accomplishments are particularly meaningful in light of the significant reduction in our capital spending program we initiated in the second half of the year due to falling commodity prices and our partners' curtailment of drilling operations.



In total, we invested $104 million in 2001, of which $99.7 million was on our drilling program, $0.7 million was on facility construction and upgrades, $2.5 million was on lease acquisitions and $1.1 million was on new seismic acquisition. The overall investment of that capital in our major properties was $56.9 million at Greater Bay Marchand, $44.7 million at East Bay and $2.4 million at East Cameron. We acquired a total of 7,277 gross new prospective acres in state lease sales with approximately 6,260 at East Bay and 1,017 at East Cameron.

Company-wide, we completed 76 of 88 well projects for a calendar year success rate of 86%. This included 59 successful workovers and recompletions, with 51 at East Bay and 8 at Greater Bay Marchand. We also successfully completed 17 new drill wells, or sidetracks of existing wells, with 2 at East Bay and 15 at Greater Bay Marchand. We have maintained our strong record of success with 88% of the projects we have undertaken since our inception being successful. That successful drilling and workover program enabled us to replace 128% of our 2001 production with new reserves. After considering negative reserve revisions due mainly to lower year-end prices, we still replaced 101% of production. Year-end reserves grew slightly to 35.8 Mmboe from 35.7 Mmboe at year-end 2000. Approximately 29% of year-end 2001 reserves were natural gas and 71% were crude oil. Over the last three years, we have replaced 125% of our production with the drill bit and 288% with acquisitions of properties.



Our finding and development costs averaged $17.53 per Boe in 2001, above the level we have achieved in the past or would expect in the future. When we curtailed our spending at mid-year, we were not able to drill all of the exploratory projects we had planned. In addition, a significant portion of our capital investments were devoted to converting proved undeveloped and proved non-producing reserves to producing status. As a result, we believe it is more appropriate to consider our reserve replacement costs since our inception for a better indication of our true costs to discover, acquire and develop our reserves. Over that time, we have invested $292 million net with an average reserve replacement cost of $6.34 per Boe, a very competitive cost for a Gulf of Mexico focused producer.

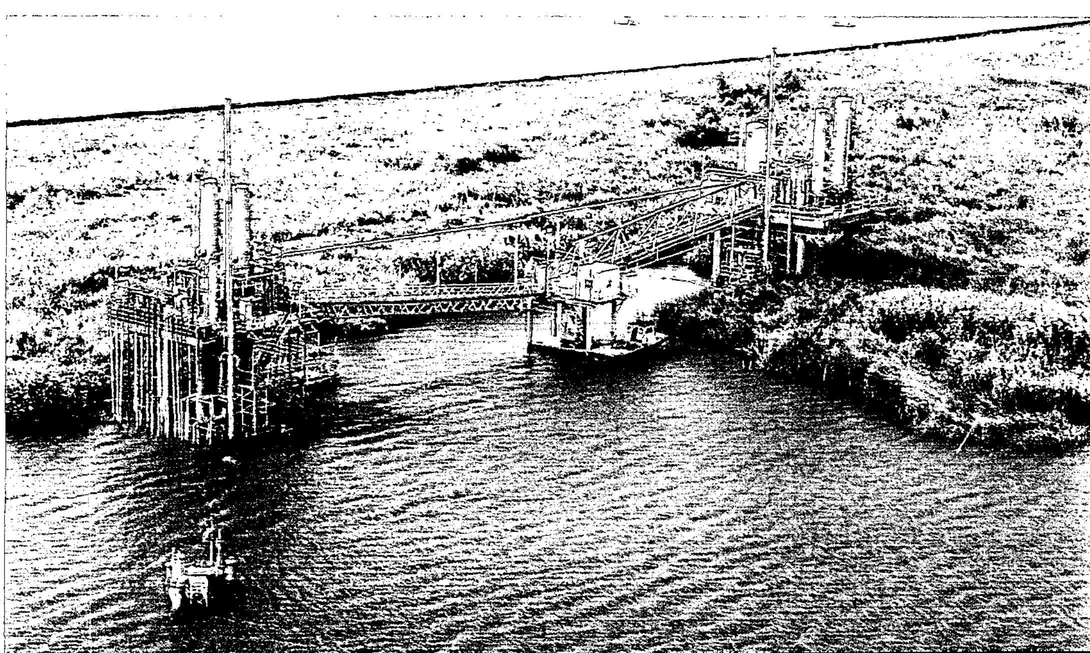
Our successful drilling program also enabled us to achieve a 57% growth in production volumes in 2001. We averaged 16,118 Boe per day versus 10,252 Boe per day in 2000. In 2001, the natural gas component of our production grew substantially to 36% compared with 26% in the prior year. We had a total of 437 gross active wells at year-end 2001 and operated over 85% of our production.

The highlight of our drilling program in 2001 was our successful higher risk, high potential exploratory well at East Cameron 9. The well was drilled to a total depth of 14,158 feet and encountered 111 feet of potential natural gas pay in eight sands. Additional high potential objectives exist within the 1,246 acres we now have under lease. This initial well tested approximately 8 Mmcf per day gross in a limited production test. Production facilities are currently under construction. Our net cost of the well including drilling and production facilities is estimated at $3.8 million. We are currently evaluating the results of the well to determine the number and location of future development wells. We own a 50% working interest and operate this significant new addition to our property portfolio.

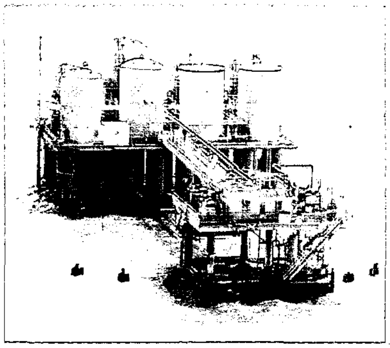
For 2002, we currently estimate our capital expenditures to range between $60 and $80 million. The risk profile for 2002 is expected to be similar to last year's, with 65% of our expenditures allocated to low risk exploitation and development projects; 25% to moderate risk exploration projects; and 10% to our ongoing high potential, higher risk exploration program that produced the East Cameron success in 2001. Our program will be comprised of development activities on East Cameron 9 and on HHOC fields, as well as exploitation activities at East Bay and Greater Bay Marchand. There will also be a significant component of moderate risk drilling and some higher risk drilling on exploration prospects developed on EPL's key properties as well as from HHOC's inventory. We will continually adjust our capital investment plans to limit our spending to our internally generated cash flow and to enable us to add new opportunities to our portfolio.

HALL-HOUSTON ACQUISITION

The most significant step we took last year in the execution of our long-term growth strategy was the successful negotiation of the acquisition of the privately-held Hall-Houston Oil Company. The transaction closed and was effective in January 2002. Founded in 1983, HHOC was an exploration-focused company based in Houston with operations concentrated in the central region of the Gulf of Mexico Shelf. Under the terms of the transaction, 96% of HHOC's \$80.2 million debt outstanding was redeemed in exchange for a combination of \$38.4 million in newly-issued EPL 11% Senior Subordinated Notes and \$38.4 million in newly-issued EPL Series D Exchangeable Convertible Preferred Stock. The balance of the debt of \$3.4 million was retired



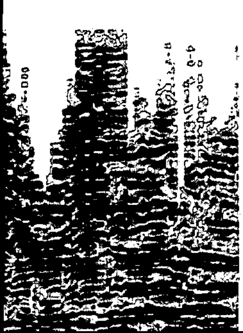
in cash. HHOC preferred and common stockholders and holders of affiliated interests received approximately $1.7 million in cash, 574,931 shares of EPL common stock and warrants to purchase four million shares of EPL common stock. The cash portions of the transaction were



funded by bank debt and our existing credit facility was increased from $65 million to $100 million. We fully preserved our financial flexibility and retained our strong balance sheet following the January 15, 2002 closing of the transaction, with our estimated debt to total capitalization ratio rising to only 30%.

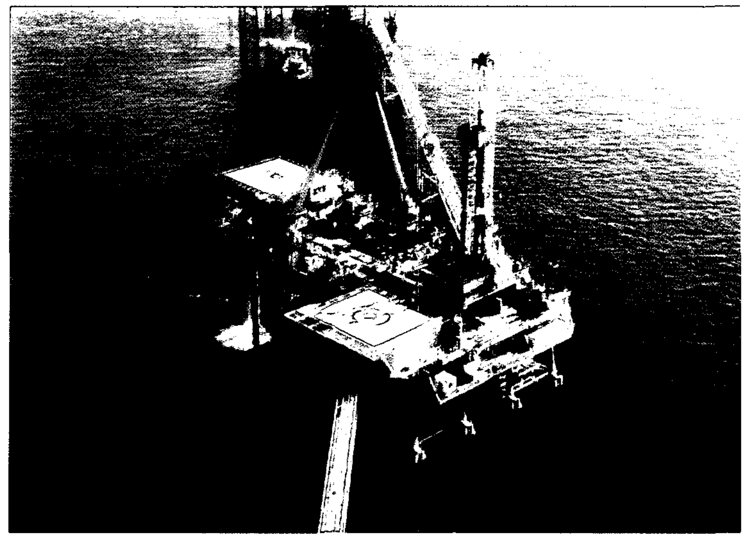
HHOC has been one of the most active independents on the Shelf since 1986. During that period, they have successfully completed 80% of their drilling projects, adding reserves at very competitive finding and developing costs. In addition to their history of exploratory drilling success, HHOC was particularly attractive to EPL because their properties, technical and management skills and corporate philosophy complemented and strengthened our own. The key attributes of the transaction include:

Adds High Quality 100% Operated Natural Gas Reserves and Production. As of January 2002, the transaction nearly doubled our natural gas reserves and increased our natural gas production by 50%. Following the transaction, our reserve base and daily production are better balanced between natural gas and oil and are less concentrated in a limited number of properties. Approximately 97% of the HHOC reserves acquired and 94% of their 2001 production were natural gas. The addition of the new properties will result in EPL's natural gas reserves growing from 29% to 43% of our total reserves, and our natural gas production rising from 36% to nearly 50% of our total production. We estimated that the proved component of their reserves acquired totaled 59.9 Bcfe as of the valuation date of November 1, 2001.



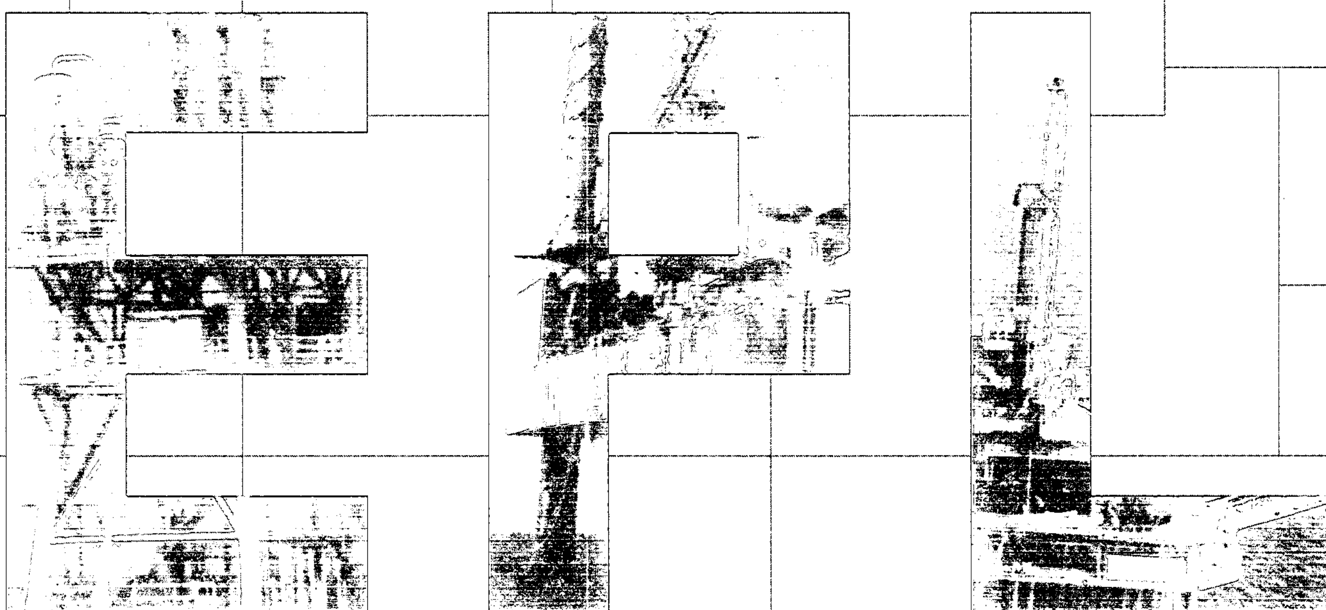
Enhances our exploratory inventory. The HHOC inventory currently includes 18 prospects which have individual gross unrisked reserve potential ranging from 5 Bcfe to in excess of 70 Bcfe, with an aggregate of over 300 Bcfe. These prospects generally fall within the moderate risk, moderate to high potential category and the working interest ranges from 20% to 100%.

These prospects add better balance to EPL's existing inventory of prospects. HHOC also has an attractive inventory of undeveloped exploratory acreage within our focus area. We are merging all of the HHOC drilling prospects into EPL's existing large inventory of opportunities and will continually high-grade all of the projects as well as add new ones as we further refine our drilling plans during the year.



Strengthens management team and technical expertise and establishes Houston presence. One of the key factors in any successful merger is finding complementary management and technical skills and a similar corporate culture. EPL and HHOC clearly shared a similar vision of building a successful explorer and aggregator of properties in the same focus area. Just like EPL, HHOC has maintained a strong commitment to the use of state-of-the-art technology to improve drilling efficiency and reduce risk. Their strong exploration expertise is a perfect match with EPL's considerable exploitation and development skills. The majority of our combined team's experience is specifically in the Gulf of Mexico Shelf.

We recently named the six-member senior management team that will lead EPL. Joining EPL senior management of Richard A. Bachmann, Chairman, President and CEO; Suzanne V. Baer, Executive Vice President and Chief Financial Officer; and Clint W. Coldren, Executive Vice President and Chief Operating Officer are Gary L. Hall, Vice Chairman and Director; Bruce R. Sidner, Executive Vice President of Exploration; and John H. Peper, Executive Vice President, General Counsel and Corporate Secretary. We are pleased to welcome these three key members of HHOC's senior management and all HHOC employees to EPL. Each of these six officers has over 20 years of technical, management or financial experience in the energy industry. EPL will continue to be headquartered in New Orleans but will now have a Houston presence through HHOC's former office which will enable us to participate in the industry networking and deal flow that a Houston presence offers.


EPL

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, 2001

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

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

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

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. ☒

The aggregate market value of the voting stock held by non-affiliates of the registrant at March 5, 2002 based on the closing price of such stock as quoted on the New York Stock Exchange on that date was $82,565,721.

As of March 5, 2002 there were 27,477,438 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 2002 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 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 document are expressly qualified in their entirety by the cautionary statements in this paragraph.

PART I

ITEMS 1 & 2. *Business and Properties*

We are an independent oil and natural gas exploration and production company concentrated in the shallow to moderate depth waters of the central region of the Gulf of Mexico Shelf. We have focused on the Central Gulf of Mexico Shelf area because it provides us with favorable geologic and economic conditions, including multiple reservoir formations, regional economies of scale, extensive infrastructure and comprehensive geologic databases. We believe that the large, established fields in this region offer a balanced and ample inventory of existing and prospective exploitation and development opportunities, as well as the long-term potential for reserve additions and production increases from deeper geologic formations. Most of our properties are located in the Terrebonne Trough area of this region. As of December 31, 2001, we had estimated proved reserves of approximately 61.8 Bcf of natural gas and 25,462 Mbbls of oil, or an aggregate of approximately 35.8 million Boe, with a present value of estimated pre-tax future net cash flows of $129.1 million (based upon year-end 2001 prices and a discount rate of 10%).

We were incorporated in January 1998 by Richard A. Bachmann, our founder, chairman, president and chief executive officer. Mr. Bachmann, the former president and chief operating officer of The Louisiana Land and Exploration Company ("LL&E"), assembled a team of geoscientists and management professionals with considerable region-specific geological, geophysical, technical and operational experience to form the foundation of our company. The industry relationships of Mr. Bachmann and the rest of our team provide us with access to the operators of the Gulf of Mexico Shelf fields that we target for redevelopment.

We have grown our company through a combination of multi-year, multi-well drill-to-earn programs and strategic acquisitions. Under our drill-to-earn programs, we use our personnel and capital to identify and pursue additional drilling opportunities on properties previously developed by our drill-to-earn partners and recover our investment through sharing revenue from the new production we establish. After successful drilling of wells, we earn an interest in the reserves we find and develop. We generally operate the properties during the drilling phase of these programs and seek to reduce costs and improve reservoir recovery efficiencies through our geophysical, technical and operational expertise.

On November 1, 2000, we priced our initial public offering of 5.75 million shares of common stock, raising $80.2 million after underwriting discounts and commissions. Our common shares are traded on the New York Stock Exchange under the symbol "EPL."

Merger with Hall-Houston Oil Company

On January 15, 2002, we closed the acquisition of Hall-Houston Oil Company and certain affiliated interests ("HHOC"). At closing, we issued $38.4 million of newly authorized Series D Exchangeable Convertible Preferred Stock, $38.4 million of 11% Senior Subordinated Notes due 2009, 574,931 shares of common stock, $5.1 million of cash, assumed HHOC's working capital deficit and issued warrants to purchase four million shares of common stock with a fair market value of approximately $3.0 million. Selling preferred stockholders of HHOC also received the right to receive contingent consideration related to future proved reserve additions from exploratory prospect acreage held by HHOC as of the closing date. The contingent consideration may be paid in common stock or cash at our option and in no event will exceed a value of $50 million. The contingent consideration, if any, will be capitalized as additional purchase price. Concurrent with the closing, we amended our bank facility to provide for a $100 million borrowing base.

The transaction strengthens our management team, expands our exploration opportunities and technical knowledge base and reduces the concentration of our reserves and production. The valuation of HHOC was based on proved reserves of 59.9 Bcfe as of November 1, 2001, of which 97% were natural gas and 60% were proved developed. As the acquisition did not close until January 2002, our December 31, 2001 financial information and reserve data do not include the operations of HHOC.

Our capital expenditures for 2001 totaled $101.5 million for exploration and development activities. For 2002, we have budgeted exploration and development expenditures of between $60 million and $80 million. This budget includes development activities on the HHOC properties as well as at East Cameron 9, exploitation activities at East Bay and Greater Bay Marchand and moderate risk exploration projects on the properties of the combined company.

Our Properties

At December 31, 2001, prior to the HHOC acquisition, we had three primary project areas: East Bay Field, Greater Bay Marchand and East Cameron 9. The Greater Bay Marchand area is comprised of three fields, South Timbalier 26, Bay Marchand and South Timbalier 22, 23 and 27, which are contiguous and together cover most of the Bay Marchand salt dome located in state and federal waters offshore Louisiana.

East Bay Field

In March 2000, we acquired the East Bay Field, and related production, compression and storage facilities for $72.3 million. East Bay is located 89 miles southeast of New Orleans near the mouth of the Mississippi River and contains producing wells located onshore along the coastline to water depths of approximately 85 feet. The field encompasses nearly 48 square miles and is comprised of three primary oil and natural gas fields, South Pass 24, 27 and 39. Through two state lease sales in 2001, we acquired acreage that is contiguous to East Bay located in South Pass blocks 22, 25, 26, 40 and 42. We are the operator of these fields and own an average 96.1% working interest. Our net revenue interest ranges from 77% to 86%. Inclusive of current year lease acquisitions, our lease area covers 38,679 gross acres (37,453 net acres) of which 4,330 gross and net acres are under federal jurisdiction while 34,349 gross acres (33,123 net acres) are under the jurisdiction of the State of Louisiana. The State of Louisiana acreage includes 7,083 gross and net unproved acres adjacent to East Bay in Louisiana state waters.

During 2001, we invested a total of $41.9 million in the drilling or sidetracking of three wells, two of which were successful, and the workover or recompletion of 57 wells, 51 of which were successful. East Bay production accounted for approximately 69% of our net daily production during 2001.

In addition, during 2001 we increased our seismic coverage in the area and merged the various surveys covering East Bay. We believe that the new 3-D data set will allow improved structural and stratigraphic interpretation for upcoming drilling activity. Total expenditures for facility improvements, compressor upgrades and seismic and lease acquisitions at East Bay totaled $2.8 million in 2001.

The Greater Bay Marchand Area

The Greater Bay Marchand area is located in state and federal waters off the coast of Louisiana approximately 60 miles south of New Orleans in water depths of 60 feet or less and encompasses nearly 100 square miles. We acquired our interests in the area in several separate transactions.

South Timbalier 26

In June 1998, we purchased our initial 20% working interest in the South Timbalier 26 field for approximately $9.0 million and assumed operatorship of the field. In March 2000, we acquired our partner's 80% interest in the field, and in April 2000, we sold 50% of our interest in the field. Our net cash outflow related to these two transactions was $8.3 million. We continue to serve as operator of the field with a 50% working interest.

Bay Marchand Drill-to-Earn Agreements with Chevron

In August 1998, we entered into a drill-to-earn agreement with Chevron U.S.A. covering the federal outer continental shelf acreage in the Bay Marchand field. As of December 31, 2001, we owned an 80% gross working interest in the drill-to-earn agreement, with the working interest in a particular operation contingent upon the nature of the operation, its success and the price of oil at the time the operation is commenced. To date, our well cost participation has ranged from 22.5% to 80%; our working interest from 19.1% to 68%; and our net revenue interest from 15.6% to 55.4% (before payout). We are the operator of the drilling and completion of wells under our program and Chevron serves as operator of production operations.

In May 2000, we expanded our presence in Bay Marchand by executing a separate drill-to-earn agreement with Chevron covering their Louisiana state water bottom acreage. We are the operator of the drilling and completion of wells covered under this program and own an 80% gross working interest in the drill-to-earn agreement. To date, our well cost participation has ranged from 16.7% to 40%; our working interest from 12.5% to 34%; and our net revenue interest from 10.3% to 28.1% (before payout). Chevron serves as operator of production operations.

The agreement, as amended, gives us the right to participate in at least 16 major operations in 2002. This agreement consolidated the drilling obligations under the outer continental shelf and state water bottom agreements described above.

South Timbalier 22, 23 and 27

In October 1999, we acquired a 12.5% working interest in South Timbalier 22, the south half of South Timbalier 23 and the northeast quarter of South Timbalier 27 for $1.4 million. In September 2000, we exercised a preferential right to purchase an additional 14.5% working interest from Texaco for $2.2 million increasing our interest in the field to approximately 27.1%. In January 2001, we acquired an additional 27% working interest in South Timbalier 27 from one of our working interest partners for $0.5 million.

During 2001, we invested a total of $56.9 million in the Greater Bay Marchand area. Our investments included the drilling or sidetracking of 19 wells, 15 of which were successful, and the workover or recompletion of 9 wells, 8 of which were successful. Production from this area accounted for approximately 31% of our net daily production in 2001.

East Cameron 9

Through two lease sales in 2001, we acquired 1,017 gross acres in East Cameron 9. In January 2002, we announced a successful discovery well, drilled in 21 feet of water approximately 2.5 miles offshore in Cameron Parish, Louisiana. We are the operator of the well and own a 50% working interest. Our share of the cost through December 31, 2001 was $2.4 million. Production facilities are currently under construction and the well is expected to be placed onstream towards the end of the second quarter or beginning of the third quarter of 2002. In January 2002, we were the successful bidder on a lease from the State of Louisiana on acreage that is contiguous to our existing East Cameron acreage. The lease covers 229 gross acres and is in 18 feet of water.

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, 2001, 2000 and 1999. The December 31, 2001 and 2000 estimates of proved reserves are based on a reserve report prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers, and does not include the volume or value of the HHOC reserves acquired in January 2002. The present values, discounted at 10% per annum, of estimated future net cash flows before income taxes shown in the table are not intended to represent the current market value of the estimated oil and natural gas reserves we own.

	As of December 31,		
	2001	2000	1999
Total estimated net proved reserves:			
Oil (Mbbls)	25,462	27,521	3,824
Natural gas (Mmcf)	61,797	49,150	12,752
Total (Mboe)	35,762	35,712	5,949
Net proved developed reserves(4):			
Oil (Mbbls)	22,176	25,024	2,715
Natural gas (Mmcf)	38,099	39,522	7,631
Total (Mboe)	28,526	31,611	3,987
Estimated future net revenues before income taxes (in thousands)	$168,007	$641,241	$76,999
Present value of estimated future net revenues before income taxes (in thousands)(1)(2)	$129,122	$489,945	$54,819
Standardized measure of discounted future net cash flows (in thousands)(3)	$123,377	$348,102	$47,177

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

(2) The December 31, 2001 amount was calculated using a period end oil price of $18.21 per barrel and a period end natural gas price of $2.71 per Mcf while the December 31, 2000 amount was calculated using a period end oil price of $25.84 per barrel and a period end natural gas price of $9.97 per Mcf.

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

(4) Net proved developed non-producing reserves as of December 31, 2001 were 8,212 Mbbls and 19,037 Mmcf.

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

Costs Incurred in Oil and Gas Activities

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

	Years Ended December 31,		
	2001	2000	1999
		(In thousands)	
Oil and gas property acquisition	$ 2,516	$119,872	$ 1,410
Exploration	45,592	18,053	1,508
Development	55,882	45,063	15,604
Total costs incurred	$103,990	$182,988	$18,522

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, 2001:

	Total Productive Wells	
	Gross	Net
Oil	386	346
Natural gas	51	45
Total	437	391

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. Fifty-eight gross oil wells and eight gross natural gas wells have dual completions.

Acreage

The following table sets forth information as of December 31, 2001 relating to acreage held by us. Developed acreage is assigned to producing wells.

	Gross Acreage	Net Acreage
Developed:		
East Bay	38,679	37,453
Greater Bay Marchand Area:		
Bay Marchand	1,320	502
South Timbalier 26	5,000	2,500
South Timbalier 22, 23 and 27	8,750	1,094
East Cameron 9.	1,017	509
Main Pass 122/133	312	163
Total	55,078	42,221
Undeveloped:		
East Bay	7,083	7,083

Well Activity

The following table shows our well activity for the years ended December 31, 2001, 2000 and 1999. 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,					
	2001		2000		1999	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	2.0	1.0	9.0	5.7	3.0	0.6
Non-Productive	—	—	2.0	1.5	—	—
Total	2.0	1.0	11.0	7.2	3.0	0.6
Exploration Wells:						
Productive	15.0	9.6	18.0	6.5	2.0	0.6
Non-Productive	5.0	4.0	1.0	0.3	1.0	0.3
Total	20.0	13.6	19.0	6.8	3.0	0.9

Title to Properties

Our properties are subject to customary royalty interests, liens under indebtedness, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interferes 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 and generally obtain title opinions from counsel only before commencement of drilling operations. We believe that title issues generally are not as likely to arise on offshore oil and natural gas properties as on onshore properties.

Regulatory Matters

Regulation of Transportation and Sale of Natural Gas

The Federal Energy Regulatory Commission ("FERC"), pursuant to the Natural Gas Act and the Natural Gas Policy Act, regulates interstate natural gas pipeline transportation rates and service conditions, both of which affect the marketing of natural gas we produce, as well as the revenues received for sales of such natural gas. Since the latter part of 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The 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 to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas has been significantly altered. The interstate pipelines' traditional role as wholesalers of natural gas has been terminated and replaced by a structure under which pipelines provide transportation and storage service on an open basis to others who buy and sell natural gas. Although the 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.

The courts have largely affirmed the significant features of Order No. 636 and the numerous related orders pertaining to individual pipelines. However, FERC continues to review and modify its regulations regarding the transportation of natural gas. For example, FERC recently issued Order Nos. 637 and 637-A which, among other things, (i) lift the cost-based cap on pipeline transportation rates in the capacity release market until September 30, 2002 for releases of pipeline capacity of less than one year, (ii) require pipelines to provide shippers with more opportunities to use capacity for which they pay by increasing rights to capacity segmentation and equalizing nomination procedures, (iii) permit pipelines to charge different maximum, cost-based rates for peak and off-peak periods and for different contract terms, (iv) permit, but do not mandate, auctions for pipeline capacity, (v) require pipelines to implement imbalance management services and to permit third-parties to provide such services in competition with the pipeline's own service, (vi) restrict the ability of pipelines to impose penalties for imbalances, overruns and non-compliance with operational flow orders, and (vii) implement a number of new pipeline reporting requirements intended to increase transparency in the market. In addition, FERC recently implemented new regulations governing the procedure for obtaining authorization to construct new pipeline facilities and has issued a policy statement establishing a presumption in favor of requiring owners of new pipeline facilities to charge rates based solely on the costs associated with such new pipeline facilities.

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 provide open-access, non-discriminatory service. FERC recently issued Order No. 639, requiring that virtually all non-proprietary pipeline transporters of natural gas on the outer continental shelf report information on their affiliations, rates and conditions of service. Among FERC's purposes in issuing such rules was the desire to increase transparency in the market to provide producers and shippers on the outer continental shelf with greater assurance of open-access services on pipelines located on the outer continental shelf and non-discriminatory rates and conditions of service on such pipelines.

We cannot accurately predict whether the 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 of material difference from those of our competitors.

Regulation of Transportation of Oil

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. 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 of material difference from those of our competitors.

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

Our subsidiary, EPL Pipeline, L.L.C., owns an approximately 12-mile oil pipeline, which transports oil produced from South Timbalier 26 on the Gulf of Mexico Shelf 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 the FERC tariff 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 reports concerning operations. Most 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 rates of production from oil and natural gas wells and the regulation of the spacing, plugging and abandonment of wells. Many states also restrict production to the market demand for oil and natural gas, and several 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 the Mineral Management Service ("MMS") and are required to comply with the regulations and orders promulgated by MMS. 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. The 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, the 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 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. However, 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 discharge of materials into the environment, or otherwise relating to the protection of the environment, 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 are subject to stringent environment regulation. 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. The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("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 the 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. 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 are unaware of any liability under CERCLA for any costs and damages resulting from hazardous substances released into the environment.

Oil Pollution Act of 1990. The Oil Pollution Act of 1990 (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 the 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 the 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 the OPA, and we believe that compliance with the OPA's financial responsibility and other operating requirements will not have a material adverse effect on us.

Clean Water Act. The Federal Water Pollution Control Act of 1972, as amended (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. 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. 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.

Resources Conservation Recovery Act. The Resource Conservation and Recovery Act of 1976, as amended ("RCRA"), is the principle 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.

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. Although at this time we cannot accurately assess the order's impact, it 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.

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operations frequently require licenses, permits and/or other governmental approvals. Several federal statutes, including the 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 the 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 Permit at East Bay. We are presently the subject of a Louisiana State Environmental Compliance Order relating to certain air emission requirements contained in an air permit issued for the East Bay Central Field Facility. That order authorized us to seek a modification of the permit which, among other things, would allow us to achieve compliance with the modified permit's air emission requirements A modified permit was subsequently obtained. Under the Environmental Compliance Order, we installed certain control technology designed to achieve compliance with the existing permit and have applied for a modification of the compliance order under the modified permit. Based on available information, we do not believe that our operations will be adversely affected by the ongoing proceedings or that any additional costs will have a material adverse impact on our financial condition or results of operations.

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 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.

Safe Drinking Water Act. Underground injection is the subsurface placement of fluid through a well or dug-hole whose depth is greater than its width. It can include placement through the reinjection of brine from oil and gas production. The Safe Drinking Water Act established 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, 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 all applicable requirements of the state underground injection control program and our permits.

Additional Factors Affecting Business

Exploration and Drilling Risks

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

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

Liability Risks

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

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

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company. We maintain insurance at levels that we believe are consistent with industry practices, but we are not fully insured against all risks. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect us.

Volatility of Oil and Natural Gas Prices

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

- changes in the global supply of and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the price and quantity of foreign imports of oil;
- political conditions, including embargoes, in or affecting other oil-producing countries;
- economic and energy infrastructure disruptions caused by acts of war, terrorist activities or national security measures deployed to protect the United States from such 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;
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

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

Uncertainty of Estimates of Oil and Natural Gas Reserves

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

In order to prepare 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 this 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 generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Marketability of Production

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

Our Limited Operating History

We have only a limited operating history upon which you can evaluate our business and prospects. Because of our limited operating history, our future results of operations are difficult to estimate accurately. We also completed two acquisitions in 2000 and the acquisition of HHOC in January 2002, which have changed, and will continue to significantly change our company.

A Significant Part of the Value of Our Production and Reserves Is Concentrated In One Property

During the month of December 2001, 74% of our net daily production came from our East Bay field. If mechanical problems, storms or other events curtail a substantial portion of this production, our cash flow would be affected adversely. Also, at December 31, 2001, approximately 70% of our proved reserves were located on this property. If the actual reserves associated with this property are less than our estimated reserves, our business, financial condition or results of operations could be adversely affected. The acquisition, in January of 2002, of HHOC will reduce the significance of, but not completely eliminate, these concentrations.

Relatively Short Production Periods for Gulf of Mexico Properties Subject 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. Given that all of our operations are on the Gulf of Mexico Shelf, our reserve replacement needs from new investments are relatively greater. Production from reserves in reservoirs in the Gulf of Mexico generally declines more rapidly than from reservoirs in many other producing regions of the world. 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 significant 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;
- the need to train and manage our employee base; and
- pressures for the continued development of our financial and information management systems.

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

Acquisition of Additional Reserves

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

- the amount of recoverable reserves;
- future oil and natural gas prices;
- estimates of operating costs;
- estimates of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- potential environmental and other liabilities.

Our assessments will not reveal all existing or potential problems, nor will they permit us to become familiar enough with the properties to assess 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 made. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Capital Requirements

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

Control by Principal Stockholder

Our principal stockholder, Evercore, together with its affiliates, beneficially owns approximately 34% of our outstanding shares of common stock and Evercore is entitled to nominate four of our directors. We increased the size of our board of directors in connection with the acquisition of HHOC in January 2002, and our board of directors now has nine members. Evercore's approval is required to take a number of corporate actions, including making acquisitions, selling assets, adopting or amending capital and operating budgets, incurring indebtedness, increasing compensation, issuing our stock, declaring dividends, engaging in hedging transactions and entering joint ventures, and Evercore may terminate the employment of Mr. Bachmann, our chairman, president and chief executive officer. As a result, Evercore is in a position to control or influence substantially the manner in which our business is operated and the outcome of stockholder votes on the election of directors and other matters.

Availability and Costs of Resources

All of our operations are on the Gulf of Mexico Shelf. Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our development and exploration operations, which could have a material adverse effect on our business, financial condition or results of operations. Periodically, drilling activity in the Gulf of Mexico has increased, and we have experienced increases in associated costs, including those related to drilling rigs, equipment, supplies and personnel and the services and products of other vendors to the industry. Increased drilling activity in the Gulf of Mexico also decreases the availability of offshore rigs. We cannot assure you that costs will not increase again or that necessary equipment and services will be available to us at economical prices.

Provisions In Our Organizational Documents and Under Delaware Law Could Delay or Prevent a Change In Control of Our Company, Which Could Adversely Affect the Price of Our Common Stock.

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

- the board of directors' ability to issue shares of preferred stock and determine the terms of the preferred stock without stockholder approval; 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. Evercore is generally exempted from these provisions.

Reliance on Key Personnel

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

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

Marketing

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 Equiva Trading Company expiring June 2003 that we assumed when we purchased the East Bay field. 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 Chevron, Equiva Trading Company and Williams Energy Marketing & Trading Company. Currently, most of our natural gas production is sold to Duke Energy Trading and Marketing, L.L.C. 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 natural gas processing arrangements for our production at our Bay Marchand and East Bay fields with Dynegy Midstream Services, L.P. and Enterprise Gas Processing, L.L.C.

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.

Competition

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

Employees

As of December 31, 2001, we had 124 full-time employees, including 41 geoscientists, engineers and technicians and 60 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 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 the financial position, results of operations or liquidity of the Company.

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	57	Chairman, President and Chief Executive Officer
Gary L. Hall	52	Vice Chairman
Suzanne V. Baer	54	Executive Vice President and Chief Financial Officer
Clinton W. Coldren	46	Executive Vice President and Chief Operating Officer
John H. Peper	49	Executive Vice President and Corporate Secretary
Bruce R. Sidner	52	Executive Vice President of Exploration

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 gas exploration company. From 1982 to 1995, Mr. Bachmann held various positions with LL&E, including director, executive vice president, chief financial officer and senior vice president of finance and administration. From 1978 to 1981, Mr. Bachmann was treasurer of Itel Corporation. Prior to 1978, Mr. Bachmann served with Exxon International, Esso Central America, Esso InterAmerica and Standard Oil of New Jersey. He is also a director of Penn Virginia Corporation and Superior Energy Services, Inc.

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

Suzanne V. Baer joined us in April 2000 as vice president and chief financial officer and was promoted to executive vice president in May 2001. Ms. Baer has 30 years of financial management, investor relations and treasury experience in the energy industry. From July 1998 until March 2000, Ms. Baer was 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.

Clinton W. Coldren joined us in March 1998 as vice president overseeing various operating activities and was promoted to executive vice president and chief operating officer in May 2001. Mr. Coldren has 24 years experience in the energy industry. Immediately prior to joining us, Mr. Coldren operated a small, family-owned project management company, Cenergy Corporation, since 1992. Mr. Coldren managed drilling and completion operations for Consolidated Natural Gas Company and participated in the establishment of Gulf

Oil's Drilling Technology Center. He began his career as a field production engineer, focused on domestic operating bases, specifically the Louisiana and Texas Gulf Coast.

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

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

PART II

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

Concurrent with the pricing of our initial public offering on November 1, 2000, our common stock was 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
2000		
First Quarter	$ —	$ —
Second Quarter	—	—
Third Quarter	—	—
Fourth Quarter	15.38	10.00
2001		
First Quarter	$13.63	$ 9.25
Second Quarter	14.00	9.00
Third Quarter	13.98	6.60
Fourth Quarter	8.60	5.60
2002		
First Quarter (through March 5, 2002)	$ 8.63	$ 5.90

On March 5, 2002, the last reported sale price of our common stock on the New York Stock Exchange was $8.25 per share.

As of March 5, 2002, there were approximately 75 holders of record of our common stock.

We have not paid any cash dividends in the past on our common stock and do not intend to pay cash dividends in the foreseeable future. We intend to retain earnings for the future 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,			January 29, 1998 (Inception) To December 31,
	2001	2000	1999	1998
	(In thousands, except per share data)			
Statement of Operations Data:				
Revenue	$ 145,927	$ 103,072	$ 9,509	$ 1,966
Income (loss) from operations (1)	20,624	(8,721)	(835)	(311)
Net income (loss)	$ 11,974	$ (18,684)	$ (2,284)	$ (705)
Net income (loss) available to common stockholders(2)	$ 11,974	$ (25,387)	$ (3,120)	$ (705)
Basic net income (loss) per common share	$ 0.45	$ (2.27)	$ (0.22)	$ (0.09)
Diluted net income (loss) per common share	$ 0.44	$ (2.27)	$ (0.22)	$ (0.09)
Cash flows provided by (used in):				
Operating activities	$ 91,847	$ 50,703	$ (4,594)	$ 8,044
Investing activities	(121,067)	(130,378)	(19,233)	(27,081)
Financing activities	25,871	60,742	45,457	19,689

	As of December 31,			
	2001	2000	1999	1998
	(In thousands)			
Balance Sheet Data:				
Total assets	$242,777	$208,149	$69,276	$40,015
Long-term debt, excluding current maturities	25,408	100	10,150	20,000
Redeemable preferred stock	—	—	56,475	—
Stockholders' equity	164,867	150,591	(3,815)	(694)

(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.

(2) Net loss available to common stockholders is computed by subtracting preferred stock dividends and accretion of issuance costs for the years ended December 31, 2000 and 1999 of $6.7 million and $0.8 million, respectively.

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

Overview

We are an independent oil and natural gas exploration and production company, incorporated in January 1998, concentrated in the shallow to moderate depth waters of the central region of the Gulf of Mexico Shelf.

We use the successful efforts method of accounting for our investment in oil and natural gas properties. Under this method, we capitalize lease acquisition costs, costs to drill and complete exploration wells in which proven reserves are discovered and costs to drill and complete development wells. Seismic, geological and geophysical, and delay rental expenditures are expensed as incurred. We conduct many of our exploration and development activities jointly with others and, accordingly, recorded amounts for our oil and natural gas properties reflect only our proportionate interest in such activities.

In March 2000, we acquired the remaining 80% working interest in South Timbalier 26 and subsequently, in April 2000, sold 50% of our working interest in South Timbalier 26. On March 31, 2000, we closed the purchase of an average 96.1% working interest in the East Bay field and in September 2000, we closed the acquisition of a 14.5% working interest in South Timbalier 22, 23 and 27.

We have included the results of operations from the East Bay and South Timbalier 26 acquisitions from the closing date of March 31, 2000 and the South Timbalier 22, 23 and 27 from the closing date of September 7, 2000. We have experienced substantial revenue and production growth as a result of these acquisitions.

On January 15, 2002, we acquired HHOC for consideration of $88.3 million and the assumption of HHOC's working capital deficit. As the closing did not occur until 2002, the impact of the acquisition is not reflected in our financial statements for fiscal 2001. The acquisition will move our operations to a more balanced natural gas and oil production profile and reduce our production exposure to any particular field. Through the acquisition we expect to add 59.0 Bcfe of proved reserves in January 2002, 97% of which are natural gas. The acquisition also includes 10 producing properties and 12 offshore exploratory blocks.

The financing related to the HHOC acquisition increased our debt level. As of March 5, 2002, we had $55.0 million outstanding under our bank credit facility and we issued $38.4 million of 11% Senior Subordinated Notes due 2009 in the acquisition. We also issued $38.4 million in Series D Exchangeable Convertible Preferred Stock.

For the foregoing reasons, the East Bay, South Timbalier 26, South Timbalier 22, 23 and 27 and HHOC acquisitions will affect the comparability of our historical results of operations with results of operations in future periods.

On November 1, 2000, we priced our initial public offering of 5.75 million shares of common stock and commenced trading the following day. After payment of underwriting discounts and commissions, we received net proceeds of $80.2 million on November 7, 2000. With the proceeds, we retired outstanding debt of $73.9 million and paid approximately $5.1 million to redeem outstanding Series C Preferred Stock.

Our revenue, profitability and future growth rate depend substantially on 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.

Results of Operations

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

	Years Ended December 31, 2001	2000	1999
Net Production (per day):			
Oil (Bbls)	10,358	7,622	1,051
Natural gas (Mcf)	34,562	15,781	2,277
Total (Boe)	16,118	10,252	1,431
Oil & Gas Revenues (in thousands):			
Oil	$ 88,416	$ 71,977	$6,678
Natural Gas	55,454	28,751	1,806
Total	143,870	100,728	8,484
Average Sales Prices(1):			
Oil (per Bbl)	$ 23.39	$ 25.80	$17.39
Natural gas (per Mcf)	4.40	4.98	2.17
Total (per Boe)	24.45	26.84	16.22
Average Costs (per Boe):			
Lease operating expense	$ 6.16	$ 6.42	$ 3.14
Taxes, other than on earnings	1.22	1.69	—
Depreciation, depletion, and amortization	7.97	6.82	8.65
General and administrative expense (exclusive of stock-based compensation)	3.09	2.95	4.99

(1) Net of the effect of hedging transactions, which reduced oil prices realizations by $1.09 and increased natural gas price realizations by $0.05 in 2001 and reduced oil prices realized by $3.80 per barrel in 2000.

Production

Crude Oil and Condensate. Our net oil production for 2001 increased to 10,358 Bbls per day from 7,622 Bbls per day in 2000. The increase was the result of 33 successful oil well operations, which commenced production in 2001, and was partially offset by natural declines from other producing wells.

Our net oil production for 2000 increased 6,571 Bbls per day from 1,051 Bbls per day in 1999. The increase was the result of the acquisitions combined with 82 successful oil well operations, which commenced production during 2000.

Natural Gas. Our net natural gas production for 2001 increased to 34,562 Mcf per day from 15,781 Mcf per day in 2000. The increase was the result of 43 successful natural gas well operations, which commenced production in 2001 and was partially offset by natural declines from other producing wells.

Our net natural gas production for 2000 increased 13,504 Mcf per day from 2,277 Mcf per day in 1999. The increase was the result of the acquisitions combined with 16 successful natural gas well operations, which commenced production in 2000.

Realized Prices

Crude Oil and Condensate. Our average realized oil price in 2001 was $23.39 per Bbl, a decrease of 9% from an average realized price of $25.80 per Bbl in 2000. Hedging activities in 2001 reduced oil price realizations by $1.09 per Bbl or 4% from the $24.48 per Bbl that would have otherwise been received. In 2000, hedging activities reduced oil price realizations by $3.80 per Bbl or 13% from the $29.60 per Bbl that would have otherwise been received.

Our average realized oil price in 2000 of $25.80 per Bbl increased 48% over an average realized price of $17.39 per Bbl in 1999. We did not have any hedging contracts in place in 1999.

Natural Gas. Our average realized natural gas price in 2001 was $4.40 per Mcf, a decrease of 12% from an average realized price of $4.98 per Mcf in 2000. Hedging activities increased natural gas realizations by $0.05 per Mcf from the $4.35 per Mcf that would have otherwise been received. We did not have hedging positions for natural gas related to 2000 production.

Our average realized natural gas price in 2000 was $4.98 per Mcf, an increase of 129% over an average realized price of $2.17 per Mcf in 1999. We did not have hedging positions for natural gas related to 1999 production.

Revenues and Net Income

Our oil and natural gas revenues increased to $143.9 million in 2001 from $100.7 million in 2000. The increase in revenues was primarily due to higher production volumes reflecting a full year of production from the acquisitions in 2000 combined with current year drilling activities. The impact of these increases was partially offset by higher costs associated with increased production volumes and lower commodity prices.

We recognized a net income of $12.0 million in 2001 compared to a loss of $18.7 million in 2000. We recorded business interruption income of $3.5 million in the first quarter of 2001 compared to $1.8 million in the fourth quarter of 2000 as a result of the rupture of a high-pressure natural gas transfer line at the East Bay field. The rupture occurred in November 2000 and the transfer line was restored to service in February 2001. In December 2001, we purchased a financially-settled put swaption (the "put swaption") which provided us with a financially-settled natural gas swap at $2.95 per mmbtu for 30,000 mmbtu per day for the period from February 2002 through January 2003. The put swaption also provided us the option to cancel the swap on January 15, 2002. In the fourth quarter of 2001, we recognized an expense of $1.9 million, related to the change in time value of the option portion of this contract.

The net loss in 2000 is attributed to one-time non-cash stock compensation charges related to the initial public offering. The Company recognized charges of $38.2 million related to the release to management and director stockholders of shares placed in escrow in 1999 and $2.1 million related to bonus shares awarded to employees. After tax, 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. Excluding the effect of the charges, we had net income of $20.8 million in 2000.

Our oil and natural gas revenues increased to $100.7 million in 2000, from $8.5 million in 1999. The increase in revenues was primarily due to sharp increases in commodity prices coupled with higher production volumes resulting from acquisitions and drilling activities. The impact of these increases was partially offset by higher costs associated with increased production volumes. We recognized a net loss of $18.7 million in 2000 compared to a net loss of $2.3 million in 1999.

Operating Expenses

Operating expenses were impacted by the following:

- Lease operating expense increased $12.2 million to $36.3 million in 2001. The increase was primarily attributable to a full year of operations from the acquisitions and the additional production from 76 successful well operations, which commenced production in 2001.

  Lease operating expense increased $22.5 million from 1999 to $24.1 million in 2000. The increase was primarily attributable to the acquisitions and the additional production from 98 successful well operations, which commenced production in 2000.

- Taxes, other than on earnings increased $0.9 million to $7.2 million in 2001. The increase in production taxes are primarily attributable to a full year of production from the acquisition of the East Bay field where a portion of the production is subject to Louisiana severance taxes and property taxes.

  Taxes, other than on earnings were $6.3 million in 2000. The production taxes are attributable to the acquisition of the East Bay field where a portion of the production is subject to Louisiana severance taxes and property taxes and to the expansion of our drill-to-earn activities at Greater Bay Marchand to areas located in Louisiana state waters, which are also subject to severance taxes. There were no such taxes in 1999.

- Exploration expenditures increased to $15.1 million in 2001 from $1.7 million in 2000. The expense in 2001 is primarily the result of seismic expenditures and delay rentals of $1.5 million and dry hole charges of $13.6 million as a result of our increased exploration program in 2001. Exploration expenditures remained consistent from 1999 to 2000.

- Depreciation, depletion and amortization increased $21.3 million to $46.9 million in 2001. This expense includes $8.1 million for the accrual of abandonment liabilities compared to $5.8 million in 2000. The overall increase was primarily due to increased production volumes and an increased depreciable asset base resulting primarily from development activities.

  Depreciation, depletion and amortization increased $21.1 million from 1999 to $25.6 million in 2000. The increase was primarily due to increased production volumes and an increased depreciable asset base resulting from the acquisitions.

- Other general and administrative expenses increased $7.1 million to $18.2 million in 2001. The increase was primarily due to the hiring of additional personnel ($2.3 million), increased consultant fees ($0.7 million), increased insurance costs ($1.6 million), increased information technology costs ($0.7 million), $0.3 million to fully reserve our hedge contract receivable from Enron and other costs associated with our increased operations.

  Other general and administrative expenses increased $8.5 million from 1999 to $11.1 million in 2000. The increase was primarily due to the hiring of additional personnel ($4.0 million), increased consultant fees ($2.4 million), increased insurance costs ($1.4 million) and other costs associated with our acquisition of the East Bay field and the additional interest in the South Timbalier 26 field on March 31, 2000.

- Non-cash stock-based compensation expense of $1.7 million was recognized in 2001 a decrease of $1.1 million from 2000. This expense relates to restricted stock and stock option grants made in April and November 2000 and will continue to decrease as the grants vest.

  Non-cash stock-based compensation expense related to our initial public offering of $40.3 million was recognized in 2000. Of this expense, $38.2 million related to the release, at the completion of the initial public offering, to management and director stockholders shares placed in escrow in 1999 and $2.1 million related to bonus shares awarded to employees upon completion of the initial public offering.

Other Income and Expense

Interest. Interest expense decreased $5.5 million to $1.9 million in 2001. The decrease is a result of lower interest rates and the repayment of borrowings under our bank credit facility which had been drawn for the acquisitions completed on March 31, 2000.

Interest expense increased $4.5 million from 1999 to $7.4 million in 2000. The increase in interest expense is a result of an increase in long-term debt outstanding during 2000 related to our acquisitions.

Gain on Sale of Oil and Gas Assets. On April 20, 2000, we sold 50% of our working interest in the South Timbalier 26 field, resulting in a gain of approximately $7.8 million.

Liquidity And Capital Resources

We intend to use cash flows from operations and our bank credit facility to fund our future development, exploration and acquisition activities. Our 2000 acquisitions significantly impacted our cash flows from operations. Our future cash flows from operations will depend on our ability to maintain and increase production on existing properties and those acquired in January 2002, our development and exploratory drilling program and the prices of oil and natural gas.

Our bank credit facility, as amended on January 15, 2002, consists of a revolving line of credit with a group of banks available through March 30, 2005 (the "bank facility"). The bank facility currently has a borrowing base of $100 million that shall be subject to redetermination based on the proved reserves of the oil and gas properties that serve as collateral for the bank facility as set out in the reserve report delivered to the bank each April 1 and October 1. The bank facility permits both prime rate based borrowings and London interbank offered rate ("LIBOR") borrowings plus a floating spread. The spread will float up or down based on our utilization of the bank facility. The spread can range from 1.50% to 2.25% above LIBOR and 0% to 0.75% above prime. The increased borrowing base under the bank facility is secured by substantially all of our assets including those acquired in the HHOC acquisition in January 2002. The bank facility contains customary events of default and requires that we satisfy various financial covenants. At March 5, 2002, we had $55 million outstanding and $45 million of credit capacity available under the bank facility.

Net cash of $121.1 million used in investing activities in 2001 included oil and gas property capital and exploration expenditures of $119.8 million and lease acquisitions of $2.5 million. Exploration expenditures resulting from dry holes are excluded from operating cash flows and included in investing activities. These capital expenditures were partially offset by $2.6 million in proceeds from the sale of equipment. During 2001, we completed 22 drilling projects and 66 recompletion/workover projects, 76 of which were successful. During 2000, we completed 30 drilling projects and 78 recompletion/workover projects, of which 98 were successful. At December 31, 2001 we had a cash overdraft of $0.8 million, which has been classified in accounts payable.

Our 2002 capital expenditure budget is focused on moderate risk exploratory activities on the leases acquired in January 2002, combined with exploitation and exploration activities on our previously existing properties. We currently expect that up to 15 percent of our budget will be spent on high risk, high potential exploration activities. Our capital expenditure plans for 2002 are currently estimated to range between $60 million and $80 million. Actual levels of capital expenditures may vary significantly due to many factors, including the integration of projects on the properties acquired from HHOC in January 2002, results of our drilling program, oil and natural gas prices, industry conditions, participation by other working interest owners and the prices of drilling rigs and other oilfield goods and services.

We have experienced and expect to continue to experience substantial working capital requirements, primarily due to our active capital expenditure program. We believe that the proceeds from working capital, cash flows from operations and borrowings under our bank facility will be sufficient to meet our capital requirements through the end of 2002. However, additional financing may be required in the future to fund our growth and capital expenditures.

Long-Term Debt and Lease Obligations

The following summarizes our obligations under long-term debt and operating lease obligations as of December 31, 2001, and includes the 11% Senior Subordinated Notes we issued in January 2002 in connection with the HHOC acquisition:

	Payments Due By Period				
	Total	1 Year	2-3 Years	4-5 Years	Thereafter
			(In Thousands)		
Long-term debt	$63,864	$ 85	$ 191	$25,217	$38,371
Operating leases	16,262	1,753	3,614	4,045	6,850
	$80,126	$1,838	$3,805	$29,262	$45,221

Hedging Activities

We enter into hedging transactions with major financial institutions to reduce exposure to fluctuations in the price of oil and natural gas. We also distribute our hedging transactions to a variety of financial institutions to reduce our exposure to counterparty credit risk. Our hedging program uses financially-settled crude oil and natural gas swaps and zero-cost collars benchmarked to the New York Mercantile Exchange ("NYMEX") West Texas Intermediate crude oil contract and Henry Hub natural gas contracts. On December 12, 2001, we purchased a put swaption in anticipation of the acquisition of HHOC. The put swaption provided us with a financially-settled natural gas swap at $2.95 per mmbtu for 10,950,000 mmbtu (30,000 mmbtu per day) for the period of February 2002 through January 2003 and the option to cancel this swap on January 15, 2002. On January 15, 2002, we exercised our right provided by the put swaption to own the swap at $2.95 per mmbtu. 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. As of December 31, 2001, the only contract in place was the put swaption. The hedged natural gas volume approximates 36% of our estimated production from proved reserves through January 2003 exclusive of the HHOC production subsequently acquired in 2002.

On January 1, 2001, we adopted Statement of Financial Accounting Standards No. 133 ("Statement 133"), as amended, Accounting for Derivative Instruments and Hedging Activities. Statement 133 establishes accounting and reporting standards requiring that derivative instruments, including certain derivative instruments embedded in other contracts, be recorded at fair market value and included as either assets or liabilities in the balance sheet. The accounting for changes in fair value depends on the intended use of the derivative and the resulting designation, which is established at the inception of the derivative. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the statement of operations. For derivative instruments designated as cash-flow hedges, changes in fair value, to the extent the hedge is effective, will be recognized in other comprehensive income (a component of stockholders' equity) until settled, when the resulting gains and losses will be recorded in earnings. Hedge ineffectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness, as defined by Statement 133, will be charged currently to earnings.

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.

As of December 31, 2001, we had no outstanding hedging transactions with Enron North America and we had fully reserved the $0.3 million due from Enron related to 61,000 barrels (1,000 barrels per day) hedged with Enron for the period of November 2001 through December 2001 at a strike price of $24.00 per barrel.

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.

- Depreciation, depletion and amortization — We utilize the successful efforts method to account for exploration and development expenditures. Successful exploratory drilling costs and all development capital expenditures are capitalized and systematically charged to expense using the units of production method based on proved developed oil and natural gas reserves as estimated by our internal engineers and an independent petroleum engineer. We also use proved developed reserves to recognize expense for future estimated dismantlement and abandonment costs. Although the engineers are knowledgeable of and follow the guidelines for reserves as established by the U.S. Securities and Exchange Commission, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. Estimated reserves are therefore, often subject to future revision, certain of which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and natural gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities.

Reserve revisions inherently lead to adjustments of depreciation rates utilized by the Company. We cannot predict the types of reserve revisions that will be required in future periods.

- Impairment of properties — We continually monitor our long-lived assets recorded in property and equipment in our consolidated balance sheet to make sure that they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the ultimate amount of recoverable oil and natural gas reserves that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas, and future inflation levels. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserves, or other changes to contracts, environmental regulations or tax laws. All of these factors must be considered when testing a property's carrying value for impairment. We cannot predict the need for, nor estimate the amount of, impairment charges that may be recorded in the future.
- 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 with major financial institutions. We may in the future enter into these and other types of hedging arrangements to reduce our exposure to fluctuations in the market prices of oil and natural gas. Under the provisions of Statement 133, we are required to record our derivative instruments at fair market value as either assets or liabilities in our consolidated balance sheet. The fair value recorded is an estimate based on future commodity prices available at the time of the calculation. The fair market value could differ from actual settlements if the other party to the contract defaults on its obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

New Accounting Policies

In 2001, the Financial Accounting Standards Board issued four new pronouncements:

- Statement 141, Business Combinations, requires the purchase method of accounting for all business combinations and applies to all business combinations initiated after June 30, 2001 and to all business combinations accounted for by the purchase method that are completed after June 30, 2001.
- Statement 142, Goodwill and Other Intangible Assets, requires that goodwill as well as other intangible assets be tested annually for impairment and is effective for fiscal years beginning after December 15, 2001.
- Statement 143, Accounting for Asset Retirement Obligations, requires entities to record the fair values of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset and is effective for fiscal years beginning after June 15, 2002.
- Statement 144, Accounting for the Impairment or Disposal of Long-Lived Assets, provides that long-lived assets to be disposed of by sale be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations, and broadens the reporting of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. This statement is effective for fiscal years beginning after December 15, 2001.

Statement 141 will apply to us with respect to the acquisition of HHOC in January 2002. Statement 142 will not apply to us at this time as we do not anticipate recording goodwill or other intangible assets as a result of the HHOC acquisition. We are currently assessing the impact of Statements 143 and 144 on our future financial condition and results of operations.

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. Under our current policies, we do not use interest rate derivative instruments to manage exposure to interest rate changes. At December 31, 2001, $25 million of our long-term debt had variable interest rates.

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, 2001, we had a natural gas swap beginning February 2002 maturing monthly through January 2003 related to the net sale of 10,950,000 Mmbtu of natural gas (30,000 Mmbtu per day) at $2.95 per Mmbtu. The hedged natural gas volume approximates 36% of our estimated production from proved reserves through January 2003. Had this contract been terminated at December 31, 2001, we estimate the loss would have been $0.5 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, 2001, the potential change in the fair value of commodity derivative instruments assuming a 10% upward movement in the underlying commodity price was a $3.1 million increase in the combined estimated loss.

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

GLOSSARY OF OIL AND NATURAL GAS TERMS

"3-D" or *"3-D seismic"* Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

"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" Billion cubic feet

"Bcfe" 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.

"Mmbtu" One million British Thermal Units.

"Mmcf" One million cubic feet of natural gas.

"payout" Generally refers to the recovery by the incurring party of its costs of drilling, completing, equipping and operating a well before another party's participation in the benefits of the well commences or is increased to a new level.

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

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

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

Item 8. *Financial Statements and Supplementary Data*

REPORT OF MANAGEMENT

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

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

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

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

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

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated balance sheets of Energy Partners, Ltd. and subsidiaries as of December 31, 2001 and 2000, 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, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Energy Partners, Ltd. and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America.

As discussed in note 2 to the consolidated financial statements, the Company changed its method of accounting for derivative instruments and hedging activities in 2001.

KPMG LLP

New Orleans, Louisiana
February 8, 2002

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2001 AND 2000
(In thousands, except share data)

	2001	2000
ASSETS		
Current assets:		
Cash and cash equivalents	$ —	$ 3,349
Trade accounts receivable	13,753	28,930
Fair value of commodity derivative instruments	2,047	—
Prepaid expenses	1,459	1,465
Total current assets	17,259	33,744
Property and equipment, at cost under the successful efforts method of accounting for oil and gas properties	287,192	195,714
Less accumulated depreciation, depletion and amortization	(63,330)	(24,927)
Net property and equipment	223,862	170,787
Other assets	363	1,357
Deferred financing costs — net of accumulated amortization of $1,995 in 2001 and $1,027 in 2000	1,293	2,261
	$242,777	$208,149
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 10,404	$ 17,322
Accrued expenses	10,985	24,639
Current maturities of long-term debt	85	—
Total current liabilities	21,474	41,961
Long-term debt	25,408	100
Deferred income taxes	16,782	9,207
Other	14,246	6,290
	77,910	57,558
Stockholders' equity:		
Preferred stock, $1 par value, authorized 1,700,000 shares; none issued	—	—
Common stock, par value $0.01 per share. Authorized 50,000,000 shares; issued and outstanding: 2001 — 26,870,757 shares; 2000 — 26,400,147 shares	269	264
Additional paid-in capital	180,995	179,679
Accumulated other comprehensive income	981	—
Accumulated deficit	(17,378)	(29,352)
Total stockholders' equity	164,867	150,591
	$242,777	$208,149

See accompanying notes to consolidated financial statements.

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
YEARS ENDED DECEMBER 31, 2001, 2000 and 1999
(In thousands, except per share data)

	2001	2000	1999
Revenue:			
Oil and gas	$143,870	$100,728	$ 8,484
Other	2,057	2,344	1,025
	145,927	103,072	9,509
Costs and expenses:			
Lease operating	36,269	24,077	1,640
Taxes, other than on earnings	7,190	6,327	—
Exploration expenditures and dry hole costs	15,141	1,703	1,570
Depreciation, depletion and amortization	46,870	25,595	4,525
General and administrative:			
Stock-based compensation	1,651	2,757	—
Other general and administrative	18,182	11,058	2,609
Stock-based compensation related to public offering	—	40,276	—
Total costs and expenses	125,303	111,793	10,344
Income (loss) from operations	20,624	(8,721)	(835)
Other income (expense):			
Interest income	329	596	312
Interest expense	(1,916)	(7,438)	(2,947)
Gain on sale of oil and gas assets	39	7,781	—
	(1,548)	939	(2,635)
Income (loss) before income taxes	19,076	(7,782)	(3,470)
Income taxes	(7,102)	(10,902)	1,186
Net income (loss)	11,974	(18,684)	(2,284)
Less dividends earned on Preferred Stock and accretion of issuance costs	—	(6,703)	(836)
Net income (loss) available to common stockholders	$ 11,974	$(25,387)	$(3,120)
Basic earnings (loss) per share	$ 0.45	$ (2.27)	$ (0.22)
Diluted earnings (loss) per share	$ 0.44	$ (2.27)	$ (0.22)
Weighted average common shares used in Computing income (loss) per share:			
Basic	26,865	11,160	14,247
Diluted	26,920	11,160	14,247

See accompanying notes to consolidated financial statements.

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
YEARS ENDED DECEMBER 31, 2001, 2000 AND 1999
(In thousands)

	Common Stock Shares	Common Stock	Additional Paid-In Capital	Accumulated Other Comprehensive Income	Accumulated Deficit	Total
Balance at December 31, 1998 . .	15,060	$150	$ —	$ —	$ (845)	$ (695)
EIF Shares cancelled	(3,292)	(32)	32	—	—	—
Dividends earned on Preferred Stock	—	—	—	—	(800)	(800)
Accretion of Preferred Stock issuance costs	—	—	—	—	(36)	(36)
Net loss	—	—	—	—	(2,284)	(2,284)
Balance at December 31, 1999 . .	11,768	118	32	—	(3,965)	(3,815)
Dividends earned on Preferred Stock	—	—	—	—	(6,340)	(6,340)
Accretion of Preferred Stock issuance costs	—	—	—	—	(363)	(363)
Stock issued for cash	5,750	58	78,623	—	—	78,681
Conversion of Preferred Stock	9,388	94	57,985	—	—	58,079
Stock-based compensation . . .	113	1	2,756	—	—	2,757
Stock-based compensation related to public offering . . .	140	1	40,275	—	—	40,276
Shares cancelled	(759)	(8)	8	—	—	—
Net loss	—	—	—	—	(18,684)	(18,684)
Balance at December 31, 2000 . .	26,400	264	179,679	—	(29,352)	150,591
Stock-based compensation . . .	—	—	1,651	—	—	1,651
Exercise of warrants	466	5	—	—	—	5
Common stock issued	5	—	—	—	—	—
Comprehensive income:						
Net income	—	—	—	—	11,974	11,974
Fair value of commodity derivative instruments . . .	—	—	—	981	—	981
Comprehensive income						12,955
Other	—	—	(335)	—	—	(335)
Balance at December 31, 2001 . .	26,871	$269	$180,995	$981	$(17,378)	$164,867

See accompanying notes to consolidated financial statements.

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
YEARS ENDED DECEMBER 31, 2001, 2000 AND 1999
(In thousands)

	2001	2000	1999
Cash flows from operating activities:			
Net income (loss)	$ 11,974	$ (18,684)	$ (2,284)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	46,870	25,595	4,525
(Gain) loss on sale of oil and gas assets	(39)	(7,781)	—
Stock-based compensation	1,651	43,033	—
Deferred income taxes	7,023	10,752	(1,186)
Exploration Expenditures	13,575	1,657	1,570
Non-cash effect of derivative instruments	1,928	—	—
Amortization of deferred financing costs	968	1,090	91
	83,950	55,662	2,716
Changes in operating assets and liabilities:			
Trade accounts receivable	15,177	(20,960)	4,782
Prepaid expenses	6	(1,164)	(216)
Fair value of commodity derivative instrument	(2,442)	—	—
Other assets	1,354	(1,357)	—
Accounts payable and accrued expenses	(6,403)	18,264	(12,133)
Other liabilities	205	258	257
Net cash provided by (used in) operating activities	91,847	50,703	(4,594)
Cash flows used in investing activities Property acquisitions	(2,516)	(119,872)	(1,410)
Exploration and development expenditures	(119,824)	(45,488)	(17,823)
Other property and equipment additions	(1,349)	(1,628)	—
Proceeds from sale of oil and gas assets	2,622	36,610	—
Net cash used in investing activities	(121,067)	(130,378)	(19,233)
Cash flows from financing activities:			
Increase in bank overdraft	808	—	—
Deferred financing costs	—	(2,836)	(332)
Repayments of long-term debt	(5,172)	(118,050)	(30,300)
Proceeds from long-term debt	30,565	108,000	20,450
Net proceeds from issuance of common stock	—	78,681	—
Net payment of Preferred Stock dividends	—	(5,053)	—
Net proceeds from issuance of Preferred Stock	—	—	55,639
Other	(330)	—	—
Net cash provided by financing activities	25,871	60,742	45,457
Net (decrease) increase in cash and cash equivalents	(3,349)	(18,933)	21,630
Cash and cash equivalents at beginning of period	3,349	22,282	652
Cash and cash equivalents at end of period	$ —	$ 3,349	$ 22,282

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 concentrated in the shallow to moderate depth waters in the central region of the Gulf of Mexico Shelf; therefore, operations are directly affected by fluctuating economic conditions of the domestic oil and natural gas industry.

(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.

(b) Property and Equipment

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

Unproved oil and gas properties are periodically assessed on a property-by-property basis, and a loss is recognized to the extent, if any, that the cost of the property has been impaired. Capitalized costs of producing oil and gas properties are depreciated and depleted by the units-of-production method.

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

The estimated costs of dismantling and abandoning offshore oil and gas properties are provided currently using the unit-of-production method. Such provision is included in depletion, depreciation and amortization in the accompanying statements of operations. As of December 31, 2001, such costs are expected to be approximately $54.9 million. To date, $13.5 million has been accrued and is included in other liabilities in the accompanying consolidated balance sheets.

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) 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.

(d) Other Revenue

The Company earned a management fee for its service as the operator of South Timbalier 26 in which it held a 20% working interest through April 2000 and currently holds a 50% working interest. The management fee revenue was recorded as the services were performed. There was no management fee recorded in 2001 and the management fee was $0.3 million and $0.8 million in 2000 and 1999, respectively.

(e) Deferred Financing Costs

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

(f) Earnings Per Share

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

(g) Revenue Recognition

The Company uses the entitlement method for recording natural gas sales revenues. 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. These amounts are not material at December 31, 2001 and 2000.

(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, 2001, 2000 and 1999, interest-bearing cash equivalents were approximately $2.1 million, $7.6 million and $23.2 million, respectively. Exploration expenditures incurred are excluded from operating cash flows and included in investing activities.

(i) Hedging Activities and New Accounting Pronouncement

The Company uses derivative commodity instruments to manage commodity price risks associated with future crude oil and natural gas production but does not use them for speculative purposes. The Company's commodity price hedging program has utilized financially-settled zero-cost collar contracts to establish floor and ceiling prices on anticipated future crude oil and natural gas production and oil and natural gas swaps to fix the price of anticipated future crude oil and natural gas production. On January 1, 2001, the Company adopted Statement of Financial Accounting Standards No. 133 (Statement 133), as amended, Accounting for Derivative Instruments and Hedging Activities. Statement 133 establishes accounting and reporting standards requiring that derivative instruments, including certain derivative instruments embedded in other contracts, be recorded at fair market value and included as either assets or liabilities in the balance sheet. The accounting for changes in fair value depends on the intended use of the derivative and the resulting designation, which is established at the inception of the derivative. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the statement of operations. For derivative instruments designated as cash-flow hedges, changes in fair value, to the extent the hedge is effective, will be recognized in other comprehensive income (a component of stockholders' equity) until settled, when the resulting gains and losses will be recorded in earnings. Hedge ineffectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness, as defined by Statement 133, will be charged currently to earnings.

(j) 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.

(k) Reclassifications

Certain reclassifications have been made to the prior period financial statements in order to conform to the classification adopted for reporting in fiscal 2001.

(3) Initial Public Offering

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. After payment of underwriting discounts and commissions, the Company received net proceeds of $80.2 million on November 7, 2000. With the proceeds, the Company retired outstanding debt of $73.9 million and paid approximately $5.1 million to redeem outstanding Series C Preferred Stock. In connection with the initial public offering, the Company converted all outstanding Preferred Stock shares into 9,388,367 shares of common stock.

In November 1999, as a requirement to complete the Preferred Stock transaction discussed in note 5, management and director stockholders placed in escrow 3,304,830 shares of common stock. These common shares were originally issued for cash in early 1998, as part of the initial capitalization of the Company, prior to the commencement of any significant operations by the Company. All or a portion of these shares were to be released from escrow only upon the attainment of specified reserve replacement targets or upon completion of a qualifying public offering. On November 7, 2000, 2,545,500 shares were released as a result of the initial public offering and the remaining shares were cancelled. Non-cash compensation expense in the fourth quarter of 2000 for the shares released was approximately $38.2 million. In addition, at the time of the initial public offering, the Company awarded 139,500 bonus shares to employees and recognized non-cash compensation expense of approximately $2.1 million related to these shares. Compensation expense was calculated using $15.00 per share, the offering price for the Company's common stock.

(4) Property and Equipment

The following is a summary of property and equipment at December 31, 2001 and 2000:

	2001	2000
	(In thousands)	
Proved oil and gas properties	$281,577	$193,001
Unproved oil and gas properties	2,273	289
Other	3,342	2,424
	287,192	195,714
Less accumulated depreciation, depletion and amortization	(63,330)	(24,927)
Net property and equipment	$223,862	$170,787

In June 1998, the Company commenced a four well drill-to-earn program covering Main Pass 122/133. Under the terms of the agreement, the Company retained 100% of the operator's working interest in the wells (the operator's interests were 100% in two wells and 69% in the other two wells). The Company is entitled to recoup its investment plus a specified return through 75% of the production stream. The operator is responsible for lease operating costs out of their retained 25% production interest. At December 31, 2001, the Company's net investment for this program was approximately $8.5 million and revenue was approximately $1.6 million for the year ended December 31, 2001. Following payout, which has not yet occurred, the Company's interest will decrease to 1%.

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

(5) Redeemable Preferred Stock

In 1999, the Company authorized 1,700,000 shares of preferred stock (Preferred Stock) having a par value of $1.00 per share, of which 1,550,000 shares are designated as Series A and Series B Redeemable Cumulative Convertible Preferred Stock and Series C Redeemable Cumulative Preferred Stock. The remaining 150,000 shares are undesignated. In November 1999, the Company entered into a stock purchase agreement whereby 600,000 shares of Series A and B Preferred Stock were sold to Evercore Capital Partners L.P. (Evercore) for $60.0 million excluding issuance costs.

The Preferred Stock earned cumulative dividends of 10% annually on the liquidation value of the Series A and B Preferred Stock plus dividends in arrears. The dividends on the Series A Preferred Stock were payable in additional fully paid and non-assessable shares (no further investment is required by the stockholders) of Series C Preferred Stock, the dividends on the Series B Preferred Stock were payable in additional fully paid and non-assessable shares of Series B Preferred Stock and the dividends on the Series C Preferred Stock were payable in cash. All accrued dividends were recorded as an increase to the carrying value of the Preferred Stock. Through November 7, 2000, there were $7.1 million of Preferred Stock dividends in arrears, of which approximately $2.0 million or 155,470 shares were Series B Preferred Stock recorded at fair value. These shares were converted to common stock at the time of the public offering and the Series C preferred stock dividends of approximately $5.1 million were paid in cash.

(6) Acquisitions and Disposition

On March 31, 2000, the Company purchased an 80% working interest in South Timbalier 26 for approximately $44.9 million. Additionally, on March 31, 2000, the Company purchased an average 96.1% working interest in East Bay Field (East Bay) for approximately $72.3 million. The entire purchase price for both acquisitions was allocated to property and equipment. The terms of the acquisitions did not contain any contingent consideration, options or future commitments.

On April 20, 2000, the Company sold 50% of its working interest in South Timbalier 26 for approximately $36.6 million, resulting in a gain of approximately $7.8 million. The proceeds from this sale were used to reduce the borrowings under the reducing revolving line of credit.

The unaudited pro forma results of operations, assuming that such acquisitions and disposition occurred on January 1, 2000, are as follows (in thousands, except per share amounts):

	2000 (Unaudited)
Pro forma:	
Revenue	$129,117
Income from operations	11,162
Net loss	(4,790)
Basic loss per common share	$ (1.03)
Diluted loss per common share	$ (1.03)

The pro forma financial information does not purport to be indicative of the results of operations that would have occurred had the acquisitions and disposition taken place at the beginning of the periods presented or future results of operations.

(7) Long-term Debt

In June 1999, the Company entered into a reducing revolving line of credit with a group of banks (bank facility). In order to finance the acquisitions discussed in note 6, the Company amended its bank facility to provide for a $90.0 million reducing revolving line of credit and a $25.0 million reducing bridge financing. As stipulated in the bank facility, the proceeds from the asset sale of $36.6 million were used to reduce the outstanding borrowings to approximately $71.8 million. In conjunction with the initial public offering described in note 3, the outstanding borrowings were repaid. At December 31, 2001, the bank facility, as amended on August 1, 2001, had a borrowing base of $65 million and was available through March 30, 2003 with interest permitted at both prime rate based borrowings and London interbank borrowing rate (LIBOR) borrowings plus a floating spread. The spread will float up or down based on our utilization of the bank facility. The spread can range from 1.25% to 2.0% above LIBOR and 0% to 0.50% above prime. The weighted average interest rate at December 31, 2001 was 3.41%. The bank facility contains customary events of default and requires that the Company satisfy various financial covenants with which the Company was in compliance at December 31, 2001. The bank facility was amended subsequent to year-end, to among other things, extend the maturity to March 30, 2005, as discussed in note 13.

The Company also has an installment note payable monthly with interest at 7.99% maturing February 2006. As of December 31, 2001, the balance outstanding was $0.5 million.

Total long-term debt outstanding at December 31, 2001 was $25.5 million which approximates fair value. Maturities of long-term debt for each of the years subsequent to December 31, 2001 are as follows: 2002 — $0.08 million, 2003 — $0.09 million, 2004 — $0.1 million, 2005 — $25.1 million and 2006 — $0.1 million.

On April 15, 1998, the Company entered into a $20.0 million financing agreement with Energy Income Fund, L.P. (EIF). On February 10, 1999, the financing agreement was amended to increase the facility to $25.0 million. On November 17, 1999, in conjunction with the Preferred Stock transaction described in note 5, the financing agreement was reduced to $10.0 million. The Company used $15.0 million of the proceeds from the Preferred Stock transaction to pay down the debt due to EIF. The remaining $10.0 million was repaid in November 2000 using proceeds from the initial public offering.

On November 17, 1999, EIF returned 3,291,720 shares of common stock as required by the Preferred Stock transaction discussed in note 5 which were cancelled. The amount originally paid by EIF for these shares of $32,377 was reclassified to additional paid-in capital in 1999.

Also, on November 17, 1999, the Company issued a warrant to EIF to purchase 928,050 shares of common stock as required by the Preferred Stock transaction discussed in note 5. The warrant was exercisable at approximately $6.50 per share or through cashless exercise, subject to adjustment as specified in the agreement, in whole or in part at any time for a period of 60 days after a qualifying public offering. The warrant was assigned no value at the date of issuance. EIF exercised its option to convert the warrant in January 2001, receiving 466,245 shares of common stock.

(8) 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. On November 17, 1999, as required by the Preferred Stock transaction discussed in note 5, management and director stockholders placed in escrow 3,304,830 shares of common stock. These shares could not be voted by the management and director stockholders and all or a portion would only be released from escrow upon the attainment of specified reserve replacement targets or upon the completion of a qualified initial public offering. Also, as a requirement of this transaction, EIF returned 3,291,720 shares of common stock, which were cancelled. All of these shares have been excluded from the calculation of weighted average common shares from November 17, 1999. On November 7, 2000, as a result of the initial public offering, 2,545,500 of the escrow shares were returned to management and director stockholders and have been included in the calculation of weighted average common shares from that date. The effect of the preferred stock dividends and accretion of issuance costs on arriving at income available to common stockholders was none in 2001, $6.7 million in 2000 and $0.8 million in 1999.

Diluted earnings per share is computed in the same manner as basic earnings per share except that the denominator is increased to include the number of additional common shares that could have been outstanding assuming the exercise of stock options and convertible preferred stock shares and the potential shares that would have a dilutive effect on earnings per share. The number of dilutive convertible preferred stock shares and stock awards used in computing diluted earnings per share were 54,976 in 2001 and none in 2000 and 1999 as these securities were antidilutive in those years.

On July 12, 2000, the board of directors approved a fifteen hundred-for-one stock split on the Company's common stock to be effected by the distribution of fifteen hundred shares for each share outstanding. On September 15, 2000, the Company increased the number of authorized common shares from 20,000 to 50,000,000 and established a par value of $0.01 per share. All shares outstanding, per share amounts and par value have been restated to reflect the stock split and the establishment of a par value.

(9) 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. 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 uses financially-settled crude oil and natural gas swaps and zero-cost collars.

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

With a financially-settled swap, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the hedged price for the transaction, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the hedged price for the transaction. With a zero-cost collar, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price of the collar, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the cap price for the collar. As of December 31, 2001, the only contract in place was the put swaption.

For the years ended December 31, 2001 and 2000, hedging activities reduced oil and gas revenues by $3.5 and $10.6 million, respectively. The Company did not have any hedging activities in 1999.

The Company's derivative instruments qualify as cash-flow hedges. In accordance with the transition provisions of Statement 133, on January 1, 2001, the Company recorded a net-of-tax cumulative-effect-type loss adjustment of $2.4 million in accumulated other comprehensive income to recognize at fair value all derivatives that were designated as cash-flow hedging instruments. During 2001, as the contracts settled, losses of $2.4 million were transferred from accumulated other comprehensive income and the fair value of outstanding derivative assets increased $1.0 million resulting in an ending balance of $1.0 in accumulated other comprehensive income at December 31, 2001 related to hedging activities.

(10) Income Taxes

Components of income tax expense (benefit) for the years ended December 31, 2001, 2000 and 1999 are as follows:

	Current	Deferred	Total
		(In thousands)	
2001:			
Federal	$ 79	$ 6,628	$ 6,707
State	—	395	395
	$ 79	$ 7,023	$ 7,102
2000:			
Federal	$150	$10,230	$10,380
State	—	522	522
	$150	$10,752	$10,902
1999:			
Federal	$ —	$(1,186)	$(1,186)
State	—	—	—
	$ —	$(1,186)	$(1,186)

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		
	2001	2000	1999
Expected tax rate	34.0%	(34.0)%	(34.0)%
Stock-based compensation	1.1	168.3	—
State taxes	2.1	6.7	—
Other	—	(0.9)	(0.2)
	37.2%	140.1%	(34.2)%

The tax effects of temporary differences that give rise to significant portions of the net deferred tax asset (liability) at December 31, 2001 and 2000 are presented below:

	2001	2000
	(In thousands)	
Deferred tax assets:		
Restricted stock awards and options	$ 1,376	$ 1,504
Federal and state net operating loss carryforwards	8,399	9,792
Fair value of commodity derivative instruments	143	—
Other	197	185
Deferred tax liability:		
Property, plant and equipment, principally due to differences in depreciation	(26,897)	(20,688)
Net deferred tax liability	$(16,782)	$ (9,207)

At December 31, 2001, the Company had net operating loss carryforwards of approximately $23.3 million, which are available to reduce future federal taxable income. The net operating loss carryforwards begin expiring in the years 2018 through 2021. 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, reversal of taxable temporary differences and tax planning strategies. As a result, no valuation allowance has been provided.

(11) Employee Benefit Plans

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. One-third of the restricted stock granted vested upon the execution of the employment agreement and one-third will vest on the first and second anniversary of the agreement. The stock options vest and are exercisable at the prices as follows: 150,000 shares at $7.67 per share after one year, 150,000 shares at $8.82 per share after two years and the remaining shares at $10.14 after three years. The grant date fair value of the restricted stock and options was $17.00. In addition, pursuant to her employment agreement, a second employee was granted 23,334 shares of restricted stock upon closing of the initial public offering, 6,667 of which will vest on the second anniversary of the employment agreement and the remainder of which will vest on the third anniversary of the employment agreement. The Company has recognized non-cash compensation expense of $1.7 million and $2.8 million in 2001 and 2000, respectively related to the restricted stock and stock option grants. At December 31, 2001, there was $0.6 million of deferred stock based compensation expense related to these awards, which will be recognized over the remaining vesting period.

The board of directors adopted the 2000 Long Term Stock Incentive Plan on September 12, 2000, and the stockholders approved the plan on September 15, 2000. The plan provides for awards of options to purchase shares of the Company's common stock and performance shares. The plan 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 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 is 2,627,130 and includes the grant of options discussed above.

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, 2001 and 2000 are as follows:

	2001		2000	
	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
Outstanding at beginning of year	568,097	$10.77	—	$ —
Granted	585,808	$10.93	568,097	$10.77
Exercised	—	$ —	—	$ —
Forfeited	(59,623)	$12.57	—	$ —
Outstanding at end of year	1,094,282	$10.76	568,097	$10.77
Exercisable at end of year	253,194	$10.15	28,000	$15.00
Available for future grants	1,782,848		2,309,033	

A summary of information regarding stock options outstanding at December 31, 2001 is as follows:

		Options Outstanding		Options Exercisable	
Range of Exercise Prices	Shares	Remaining Contractual Life	Weighted Average Price	Shares	Weighted Average Price
$7.67–$8.82	300,000	4–5 years	$ 8.25	150,000	$ 7.67
$10.14–$15.00	794,282	5–10 years	$11.70	103,194	$13.75

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). However, Statement of Financial Accounting Standards No. 123 (Statement 123), "Accounting For Stock-Based Compensation" permits the continued use of the intrinsic value-based method prescribed by Opinion No. 25 but requires additional disclosures, including pro forma calculations of earnings and net earnings per share as if the fair value method of accounting prescribed by Statement 123 had been applied. If compensation expense for the Company's stock option plans had been determined using the fair-value method in Statement 123, the Company's net income (loss) and earnings (loss) per share would have been as shown in the pro forma amounts below: (in thousands, except per share amounts)

		2001	2000
Net income (loss) available to common stockholders	As reported	$11,974	$(25,387)
	Pro forma	$10,685	$(25,575)
Basic earnings (loss) per share	As reported	$ 0.45	$ (2.27)
	Pro forma	$ 0.40	$ (2.29)
Diluted earnings (loss) per share	As reported	$ 0.44	$ (2.27)
	Pro forma	$ 0.40	$ (2.29)
Average fair value of grants during the year		$ 3.47	$ 4.68

Black-Scholes option pricing model assumptions:

Risk free interest rate	4.5%	5.0%
Expected life (years)	2.5 to 5	2.5 to 7
Volatility	35.00%	41.00%
Dividend yield	—	—

(12) Commitments and Contingencies

The Company has operating leases for office space and equipment, which expire on various dates through 2011.

Future minimum lease commitments as of December 31, 2001 under these operating leases are as follows (in thousands):

2002	$ 1,753
2003	1,756
2004	1,858
2005	1,786
2006	2,259
Thereafter	6,850
	$16,262

Rent expense for the years ended December 31, 2001, 2000 and 1999 was $1.8 million, $0.9 million and $0.4 million, respectively.

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

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.

(13) Subsequent Event

On January 15, 2002, the Company closed the acquisition of HHOC for $88.3 million and the assumption of HHOC's working capital deficit. At closing, the Company issued $38.4 million of newly authorized and issued Series D Exchangeable Convertible Preferred Stock (Series D Preferred Stock), $38.4 million of 11% Senior Subordinated Notes, due 2009 (the Notes), 574,931 shares of common stock, $5.1 million of cash and issued warrants to purchase four million shares of common stock. Of the warrants, one million have a strike price of $9.00 and three million have a strike price of $11.00 per share. The warrants have a fair value of approximately $3.0 million. Selling preferred stockholders of HHOC also received the right to receive contingent consideration related to future proved reserve additions from exploratory prospect acreage held by HHOC as of the closing date. The contingent consideration may be paid in common stock or cash at the Company's option and in no event will exceed a value of $50 million. The contingent consideration, if any, will be capitalized as additional purchase price. 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 among working capital and oil and gas assets.

In connection with the acquisition of HHOC, in January 2002, the Board of Directors of the Company resolved to designate a new class of preferred stock. 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 January 15 and July 15 of each year as follows:

Dividend Period Ending	Dividend Rate
July 15, 2002 to January 15, 2005	7%
July 15, 2005 to January 15, 2006	8%
July 15, 2006 to January 15, 2007	9%
July 15, 2007 thereafter	10%

Any dividends accrued on or prior to January 15, 2006 shall when declared be payable in cash at the dividend rate per share based on the stated value of $100. Any dividends accrued after January 15, 2006 and on or before January 14, 2009 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 January 15, 2005, 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 addition, as stated above, the Company issued the Notes due January 15, 2009 with annual interest of 11%, payable semi-annually on each January 15 and July 15, commencing July 15, 2002. If at any time while the Notes are outstanding, the Company completes a public or Rule 144A offering of debt securities, to the extent permitted by the Company's bank facility, the proceeds of such offering will be used to prepay the principal amount of the Notes plus accrued interest.

Concurrent with the closing, the Company amended its bank facility. The new terms provide for a $100 million borrowing base that shall be subject to redetermination based on the proved reserves of the oil and gas properties that serve as collateral for the bank facility as set out in the reserve report delivered to the bank each April 1 and October 1. The bank facility as amended is available through March 30, 2005 with interest permitted at both prime rate based borrowings and LIBOR borrowings plus a floating spread. The spread will float up or down based on our utilization of the bank facility. The spread can range from 1.50% to 2.5% above LIBOR and 0% to 0.75% above prime. Indebtedness under the bank facility is secured by substantially all of the combined assets of the Company and HHOC.

(14) Supplemental Cash Flow Information

The following is supplemental cash flow information:

	Years Ended December 31,		
	2001	2000	1999
	(In thousands)		
Interest paid, net of amounts capitalized	$842	$6,534	$3,192
Income taxes paid	$ 79	$ 150	$ —

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

	Years Ended December 31,		
	2001	2000	1999
	(In thousands)		
Dividends earned on Preferred Stock	$—	$ 6,340	$800
Conversion of Preferred Stock	$—	$58,079	$ —
Conversion of Warrants	$ 5	$ —	$ —

(15) Related Party

The Company's President and Chief Executive Officer serves on the board of directors of a company that provides contract operations and other production services to the Company. The Company incurred expenses from this service provider of $2.2 million, $4.4 million and $4.7 million in 2001, 2000 and 1999, respectively. Loss of this service provider would not have a material adverse effect on the operations of the Company.

Pursuant to the Company's stockholder agreement with Evercore, the Company paid an affiliate of Evercore a monitoring fee of $250,000 in 2001 and 2000. This fee will be paid annually until Evercore beneficially owns less than 10% of the Company. An affiliate of Evercore provided investment-banking advisory services to the Company in relation to the January 2002 acquisition of HHOC. The Company will pay $0.4 million for these services in 2002.

On January 21, 1999, the Board of Directors approved the establishment of a 3% overriding royalty fund for executive stockholders. The royalty was to be paid based on revenue on all existing properties to the extent that funds were available from net operating income. A formal plan was not developed, however at the time of the Preferred Stock transaction described in note 5, the Board of Directors approved a payment to the executive stockholders approximating the 3% override as if the plan had been formalized. The charge of approximately $490,000 has been recorded in the 1999 statement of operations. The Company no longer has any obligation for the overriding royalty fund.

(16) Interim Financial Information (Unaudited)

The following is a summary of consolidated unaudited interim financial information for the years ended December 31, 2001 and 2000 (in thousands, except per share data):

	Three Months Ended			
	March 31	June 30	Sept. 30	Dec. 31
2001				
Revenues	$49,930	$37,219	$33,680	$25,098
Costs and Expenses	27,618	31,617	36,263	29,805
Income (loss) from operations	22,312	5,602	(2,583)	(4,707)
Net income (loss)	14,037	3,424	(2,069)	(3,418)
Earnings (loss) per share:				
Basic	$ 0.52	$ 0.13	$ (0.08)	$ (0.13)
Diluted	0.52	0.13	(0.08)	(0.13)

	Three Months Ended			
	March 31	June 30	Sept. 30	Dec. 31
2000				
Revenues	$ 4,243	$26,113	$30,734	$ 41,982
Costs and Expenses	4,009	18,671	19,717	69,396 (2)
Income (loss) from operations	234	7,442	11,017	(27,414)
Net income (loss)	60	8,195(1)	5,191	(32,130)(2)
Net income (loss) available to common stockholders	(1,586)	5,609	3,448	(32,858)
Earnings (loss)per share:				
Basic	$ (0.13)	$ 0.66	$ 0.40	$ (1.73)
Diluted	(0.13)	0.46	0.29	(1.73)

(1) Includes the effect of a gain of $7.8 million from the sale of oil and gas assets.

(2) 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.

(17) Supplementary Oil And Gas Disclosures — (Unaudited)

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, 1998	2,861	12,534
Extensions, discoveries and other additions	1,079	267
Purchase of reserves in place	268	782
Production	(384)	(831)
December 31, 1999	3,824	12,752
Purchase of reserves in place	27,021	41,869
Sale of reserves	(3,535)	(10,673)
Extensions, discoveries and other additions	3,001	10,978
Production	(2,790)	(5,776)
December 31, 2000	27,521	49,150
Purchases of reserves in place	117	301
Extensions, discoveries and other additions	2,797	28,383
Revisions	(1,192)	(3,422)
Production	(3,781)	(12,615)
December 31, 2001	25,462	61,797
Proved developed reserves:		
December 31, 1999.	2,715	7,631
December 31, 2000.	25,024	39,522
December 31, 2001.	22,176	38,099

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

	2001	2000
	(In thousands)	
Proved properties	$281,577	$193,001
Unproved properties	2,273	289
Accumulated depreciation, depletion and amortization	(61,981)	(24,253)
Net capitalized costs	$221,869	$169,037

Costs incurred for oil and gas property acquisition, exploration and development activities for the years ended December 31, 2001, 2000 and 1999 are as follows:

	2001	2000	1999
		(In thousands)	
Oil and gas property acquisition	$ 2,516	$119,872	$ 1,410
Exploration	45,592	18,053	1,508
Development	55,882	45,063	15,604
Total costs incurred	$103,990	$182,988	$18,522

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 gas reserves is as follows:

	2001	2000	1999
		(In thousands)	
Future cash inflows	$ 630,941	$1,200,880	$125,038
Future production costs	(293,945)	(391,698)	(29,036)
Future development and abandonment costs	(168,989)	(167,941)	(19,003)
Future income tax expense	(4,688)	(183,901)	(12,906)
Future net cash flows after income taxes	163,319	457,340	64,093
10% annual discount for estimated timing of cash flows	(39,942)	(109,238)	(16,916)
Standardized measure of discounted future net cash flows	$ 123,377	$ 348,102	$ 47,177

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved oil and gas reserves for the years ended December 31, 2001, 2000 and 1999 is as follows:

	2001	2000	1999
		(In thousands)	
Beginning of the period	$ 348,102	$ 47,177	$ 24,889
Sales and transfers of oil and gas produced, net of production costs	(100,411)	(70,324)	(6,843)
Net changes in prices and production costs	(349,126)	58,169	13,232
Extensions, discoveries and improved recoveries, net of future production costs	49,217	23,992	18,130
Revision of quantity estimates	(12,619)	—	—
Previously estimated development costs incurred during the period	10,861	7,341	18,141
Purchase and sales of reserves in place	637	419,376	1,410
Changes in estimated future development costs	(20,014)	(8,910)	(14,352)
Changes in production rates (timing) and other	11,638	—	—
Accretion of discount	48,995	5,482	42
Net change in income taxes	136,097	(134,201)	(7,472)
Net (decrease) increase	(224,725)	300,925	22,288
End of period	$ 123,377	$ 348,102	$ 47,177

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2001 was based on period end prices of $2.71 per Mcf for natural gas and $18.21 per barrel for crude oil. The December 31, 2000 computation was based on period end prices of $9.97 per Mcf for natural gas and $25.84 per barrel for crude oil. Spot prices as at February 28, 2002 were $2.44 per Mmbtu for natural gas and $18.00 per barrel for crude oil before adjustment for lease quality, transportation fees and price differentials. Had these prices been used, the present value of future net revenues relating to proved reserves would have been increased.

ITEM 9. *Changes in and Disagreements With Accountants on Accounting and Financial Disclosure*

None.

PART III

For information concerning Item 10 — Directors and Executive Officers of the Registrant, Item 11 — Executive Compensation, Item 12 — Security Ownership of Certain Beneficial Owners and Management and Item 13 — Certain Relationships and Related Transactions, see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on May 9, 2002, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference, and "Part I — Item 4A. Executive Officers".

PART IV

ITEM 14. *Exhibits, Financial Statement Schedules, and Reports on Form 8-K*

(A) 1. Financial Statements:

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

Independent Auditor's Report

Consolidated Balance Sheets as of December 31, 2001 and 2000

Consolidated Statements of Operations for the years ended December 31, 2001, 2000 and 1999

Consolidated Statement of Changes in Stockholders' Equity for the years ended December 31, 2001, 2000 and 1999

Consolidated Statement of Cash Flows for the years ended December 31, 2001, 2000 and 1999

Notes to the Consolidated Financial Statements

2. 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 September 12, 2000 (incorporated by reference to Exhibit 3.3 to EPL's registration statement on Form S-1 (File No. 333-42876)).
4.1	— Stockholder Agreement dated as of November 17, 1999 (incorporated by reference to Exhibit 4.4 to EPL's registration statement on Form S-1 (File No. 333-42876)).
4.2	— Form of First Amendment to Stockholder Agreement dated as of September 29, 2000 (incorporated by reference to Exhibit 4.7 to EPL's registration statement on Form S-1 (File No. 333-42876)).

Exhibit Number	Title
4.3	— Second Amendment to Stockholder Agreement dated as of January 15, 2002 (incorporated by reference to Exhibit 4.1 of EPL's Form 8-K filed January 22, 2002).
4.4	— Registration Rights Agreement by and between Energy Partners, Ltd., Evercore Capital Partners L.P., Evercore Capital Partners (NQ) L.P., Evercore Capital Offshore Partners L.P., Energy Income Fund, L.P. and the Individual Shareholders of the Company signatories thereto dated as of November 17, 1999 (incorporated by reference to Exhibit 4.5 to EPL's registration statement on Form S-1 (File No. 333-42876)).
10.1	— Patent License Agreement between VTV, Incorporated and Energy Partners, Ltd. dated as of May 16, 1998 (incorporated by reference to Exhibit 10.9 to EPL's registration statement on Form S-1 (File No. 333-42876)).
10.2*	— Amended and Restated 2000 Long Term Stock Incentive Plan.
10.3	— 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)).
10.4*	— First Amendment to 2000 Stock Option Plan for Non-Employee Directors.
10.5	— Stock and Deferral Plan for Non-Employee Directors (incorporated by reference to Exhibit 99.3 to EPL's registration statement on Form S-8 (File No. 333-55940)).
10.6*	— First Amendment to Stock and Deferral Plan for Non-Employee Directors.
10.7	— Employment and Stock Ownership Agreement by and between Energy Partners, Ltd. and Richard A. Bachmann dated as of June 5, 1998 (incorporated by reference to Exhibit 10.10 to EPL's registration statement on Form S-1 (File No. 333-42876)).
10.8	— First Amendment to Employment and Stock Ownership Agreement by and between Energy Partners, Ltd. and Richard A. Bachmann dated as of November 17, 1999 (incorporated by reference to Exhibit 10.11 to EPL's registration statement on Form S-1 (File No. 333-42876)).
10.9	— Employment and Stock Ownership Agreement by and between Energy Partners, Ltd. and Suzanne V. Baer dated as of March 18, 2000 (incorporated by reference to Exhibit 10.12 to EPL's registration statement on Form S-1 (File No. 333-42876)).
10.10	— Form of Employment and Stock Ownership Agreement by and between Energy Partners, Ltd. and Clinton W. Coldren dated as of June 5, 1998 (incorporated by reference to Exhibit 10.13 to EPL's registration statement on Form S-1 (File No. 333-42876)).
10.11	— Form of First Amendment to Employment and Stock Ownership Agreement by and between Energy Partners, Ltd. and Clinton W. Coldren dated as of November 17, 1999 (incorporated by reference to Exhibit 10.15 to EPL's registration statement on Form S-1 (File No. 333-42876)).
10.12	— Form of Second Amendment to Employment and Stock Ownership Agreement by and between Energy Partners, Ltd. and Richard A. Bachmann and Clinton W. Coldren, dated as of September 29, 2000 (incorporated by reference to Exhibit 10.30 to EPL's registration statement on Form S-1 (File No. 333-42876)).
10.13	— Employment and Stock Ownership Agreement by and between Energy Partners, Ltd. and Gary L. Hall (incorporated by reference to Exhibit 10.2 of EPL's Form 8-K filed January 22, 2002).
10.14	— Employment and Stock Ownership Agreement by and between Energy Partners, Ltd. and John H. Peper (incorporated by reference to Exhibit 10.3 of EPL's Form 8-K filed January 22, 2002).
10.15	— Employment and Stock Ownership Agreement by and between Energy Partners, Ltd. and Bruce R. Sidner (incorporated by reference to Exhibit 10.4 of EPL's Form 8-K filed January 22, 2002).
10.16	— Second Amended and Restated Revolving Credit Agreement dated January 15, 2002, among Energy Partners, Ltd., Hall-Houston Oil Company, Bank One, NA and the several banks and financial institutions from time to time parties thereto (incorporated by reference to Exhibit 10.1 of EPL's Form 8-K filed January 22, 2002).
10.17	— 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)).

Exhibit Number	Title
10.18	— Farmout Agreement by and between Chevron U.S.A. Inc., Kewanee Industries, Inc. and Energy Partners, Ltd. dated as of June 9, 1998 (incorporated by reference to Exhibit 10.19 to EPL's registration statement on Form S-1 (File No. 333-42876)).
10.19	— Purchase and Sale Agreement between Union Oil Company of California and Energy Partners, Ltd. dated as of March 31, 2000 (incorporated by reference to Exhibit 10.20 to EPL's registration statement on Form S-1 (File No. 333-42876)).
10.20	— Purchase and Sale Agreement between Energy Partners Ltd. and Vastar Resources, Inc. dated as of April 20, 2000 (incorporated by reference to Exhibit 10.22 to EPL's registration statement on Form S-1 (File No. 333-42876)).
10.21	— Purchase and Sale Agreement by and between Texaco Exploration and Production Inc. and Energy Partners, Ltd. dated as of September 7, 2000 (incorporated by reference to Exhibit 10.32 to EPL's registration statement on Form S-1 (File No. 333-42876)).
10.22	— Purchase and Sale Agreement by and between Online Resources, Inc. and Energy Partners, Ltd. dated as of October 29, 1999 (incorporated by reference to Exhibit 10.33 to EPL's registration statement on Form S-1 (File No. 333-42876)).
10.23	— Farmout Agreement between Chevron U.S.A. Inc. and Energy Partners, Ltd. and Wheless Anderson L.L.C. dated as of August 21, 2000 covering the North Flank of Bay Marchand (incorporated by reference to Exhibit 10.34 to EPL's registration statement on Form S-1 (File No. 333-42876)).
10.24	— Assignment and Bill of Sale between Hughes-Rawls, L.L.C. and Energy Partners, Ltd. dated as of August 25, 1998 (incorporated by reference to Exhibit 10.38 to EPL's registration statement on Form S-1 (File No. 333-42876)).
10.25	— Agreement and Plan of Merger by and among Energy Partners, Ltd., Saints Acquisition Subsidiary, Inc. and Hall-Houston Oil Company dated as of December 16, 2001 (incorporated by reference to Exhibit 2.1 of EPL's Form 8-K filed December 20, 2001).
10.26	— Amendment No. 1 dated as of January 15, 2002 to Agreement and Plan of Merger dated as of December 16, 2001, by and among Energy Partners, Ltd., Saints Acquisition Subsidiary, Inc., and Hall-Houston Oil Company (incorporated by reference to Exhibit 2.2 of EPL's Form 8-K filed January 22, 2002).
10.27	— Assignment and Amendment of Purchase and Sale Agreement dated as of January 15, 2002, by and among Energy Partners, Ltd., Hall-Houston Oil Company, Hall Partners, L.P., LPCR Investment Group, L.P., Hall Consulting Company, Inc., Hall Equities, Inc., Hall Family Trust, Bruce R. Sidner, Wayne P. Hall, and John H. Peper (incorporated by reference to Exhibit 2.3 of EPL's Form 8-K filed January 22, 2002).
10.28	— Principal Shareholder Voting Agreement dated as of January 15, 2002, by and among Hall-Houston Oil Company, Evercore Capital Partners L.P., Evercore Capital Partners (NQ) L.P., Evercore Co-Investment Partnership L.P., Evercore Capital Offshore Partners L.P., Energy Income Fund, L.P., and Richard A. Bachmann (incorporated by reference to Exhibit 2.4 of EPL's Form 8-K filed January 22, 2002).
10.29	— Earn-Out 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).
21.1*	— Subsidiaries of Energy Partners, Ltd.
23.1*	— Consent of KPMG LLP.
23.2*	— Consent of Netherland, Sewell & Associates, Inc.
99.1*	— Report of Independent Petroleum Engineers dated as of February 1, 2002.

* Filed herewith

(B) Reports on Form 8-K

On December 20, 2001, EPL filed a current report on Form 8-K reporting under Items 5 and 7, the announcement of a definitive agreement to acquire Hall-Houston Oil Company.

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 Richard A. Bachmann	Chairman, President and Chief Executive Officer (Principal Executive Officer)	March 15, 2002
/s/ SUZANNE V. BAER Suzanne V. Baer	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 15, 2002
/s/ AUSTIN M. BEUTNER Austin M. Beutner	Director	March 15, 2002
/s/ JOHN C. BUMGARNER,JR. John C. Bumgarner, Jr.	Director	March 15, 2002
/s/ HAROLD D. CARTER Harold D. Carter	Director	March 15, 2002
/s/ ROBERT D. GERSHEN Robert D. Gershen	Director	March 15, 2002
/s/ GARY L. HALL Gary L. Hall	Director	March 15, 2002
/s/ WILLIAM O. HILTZ William O. Hiltz	Director	March 15, 2002
/s/ EAMON M. KELLY Eamon M. Kelly	Director	March 15, 2002
/s/ JOHN G. PHILLIPS John G. Phillips	Director	March 15, 2002

BOARD OF DIRECTORS

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

Austin M. Beutner (2)
Founding Partner
Evercore Capital Partners, L.P.

John C. Bumgarner, Jr. (2)
Chief Operating Officer and President of Strategic Investments for Williams Communications Group

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

Robert D. Gershen (2)
President
Associated Energy Managers

Gary L. Hall
Vice Chairman
Energy Partners, Ltd.

William O. Hiltz (1)
Partner
Evercore Capital Partners, L.P.

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

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

(1) Audit Committee
(2) Compensation Committee

ABBREVIATIONS

Bbl	Barrel
Bcfe	Billion cubic feet equivalent*
Bcf	Billion cubic feet
Boe	Barrels of oil equivalent*
HHOC	Hall-Houston Oil Company
Mbbls	Thousands of barrels
Mboe	Thousands of barrels of oil equivalent*
Mmboe	Millions of barrels of oil equivalent*
Mmbtu	Million British Thermal Units
Mcf	Thousand cubic feet
Mmcf	Million cubic feet
Tcf	Trillion cubic feet
EPL	Energy Partners, Ltd.
Shelf	Shallow waters of the outer continental shelf of the Gulf of Mexico

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

OFFICERS

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

Gary L. Hall
Vice Chairman of the Board

Suzanne V. Baer
Executive Vice President and Chief Financial Officer

Clinton W. Coldren
Executive Vice President and Chief Opertating Officer

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

Bruce R. Sidner
Executive Vice President of Exploration

Kenneth P. Smith
Treasurer

L. Keith Vincent
Vice President

Louis E. Willhoit, Jr.
Vice President

CORPORATE INFORMATION

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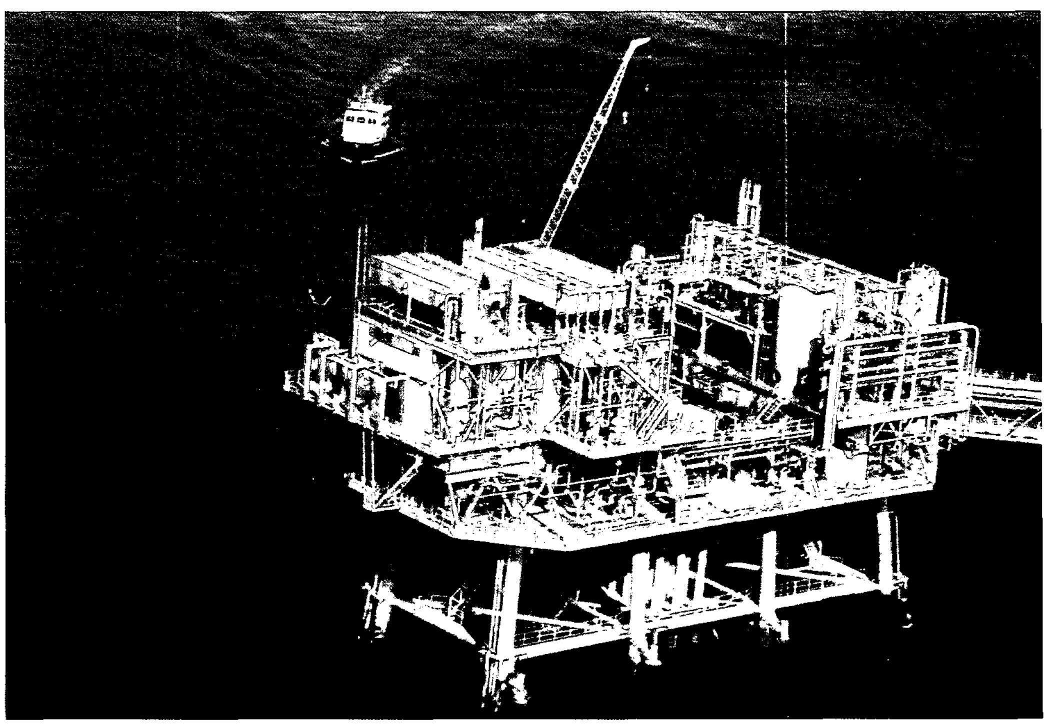
Suite 3400
New Orleans, LA 70170
504-569-1875

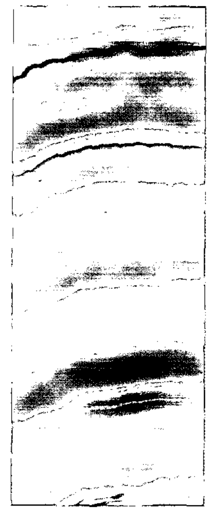
Registrar and Transfer Agent
Mellon Investor Services
85 Challenger Road
Ridgefield Park, NJ 07660
800-635-9270
www.melloninvestor.com

Annual Meeting
The Annual Meeting of Stockholders will be held in New Orleans on Thursday, May 9, 2002.

Stock Exchange Listing
New York Stock Exchange
Symbol: EPL

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





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