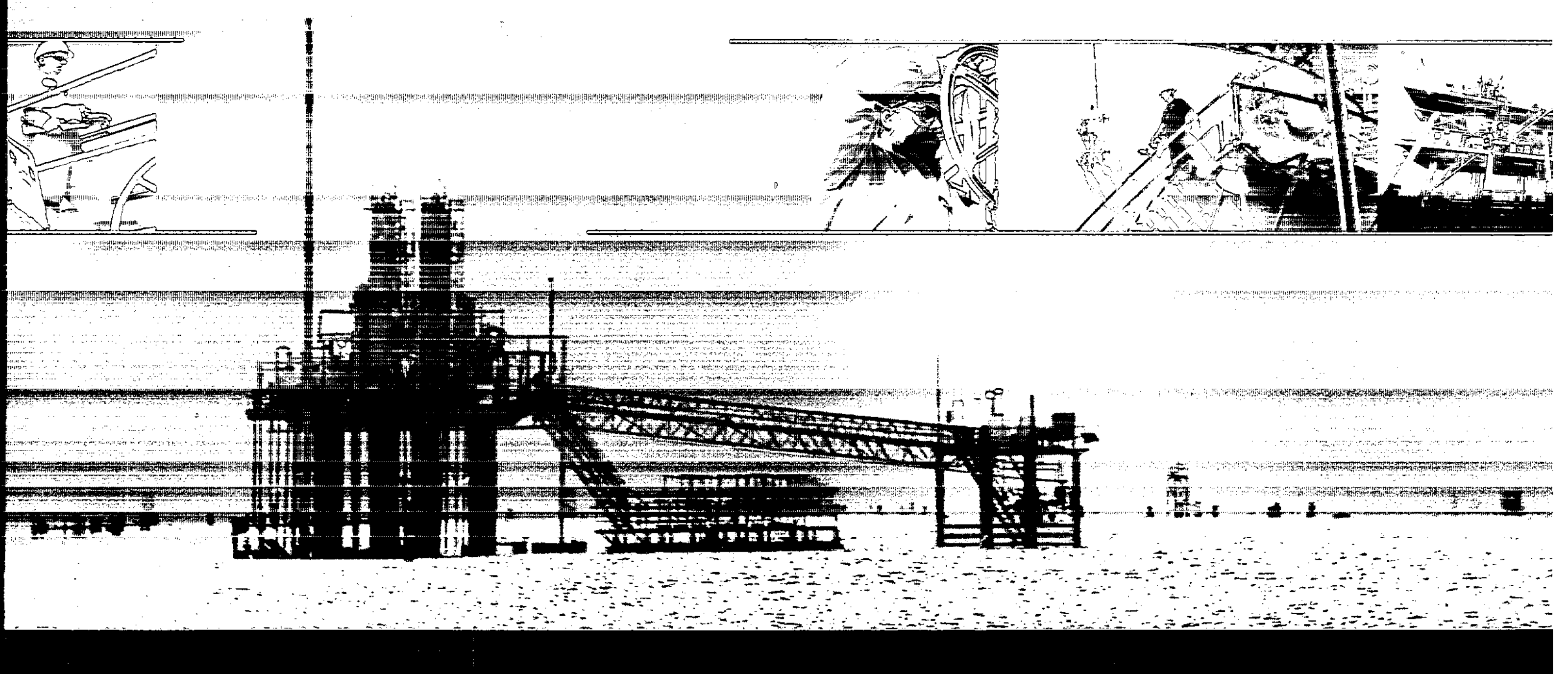
EPL 2002

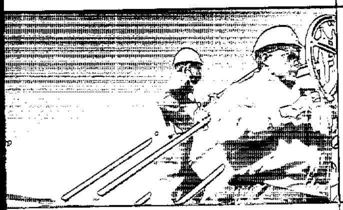
Energy Partners, Ltd.

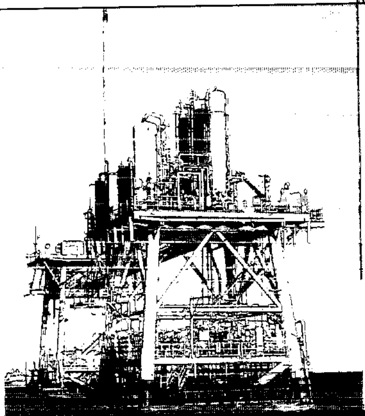
THE RIGHT PEOPLE. THE RIGHT PROPERTIES.



Energy Partners, Ltd.

Founded in 1998, Energy Partners, Ltd. (EPL) is an independent exploration and production company concentrated in the shallow to moderate depth waters of the Gulf of Mexico Shelf. We have focused on this area because it provides us with favorable geologic and economic conditions and an extensive array of exploration, exploitation and development opportunities. In 2002, EPL undertook the most aggressive exploratory drilling program in its history and achieved outstanding results. This report describes the details of this pivotal year in EPL's history.





During 2002, EPL made tangible progress in its evolution from a successful exploitation and development company to a growing exploration, exploitation and production company.

The first half of the year was dedicated to the integration of Hall-Houston Oil Company (HHOC) and the rationalization of our combined portfolio of drilling opportunities. That acquisition, which closed in January of 2002, added the missing piece of the EPL puzzle, the exploration component. While EPL had begun building its exploration team prior to the acquisition, HHOC provided us with the exploratory leadership and expanded portfolio of moderate risk prospects that we needed to execute our strategy.

By mid-year, we finalized our drilling plans for the year and moved forward in earnest with our program of 17 planned wells. The first three exploratory wells drilled, all moderate risk, moderate potential wells, were successes. We quickly moved forward with development plans for those new wells. Unfortunately, in early September, the Gulf of Mexico confronted the most active tropical weather in many years. In less than 90 days, we experienced six named storms that caused multiple shutdowns of production, significant facility damage and extended construction and drilling delays. While our operations staff did an excellent job of protecting lives and property, we nonetheless incurred a significant, but temporary, loss of production of 1,000 Boe and 2,700 Boe per day in the third and fourth quarters, respectively. This equated to about $7.9 million in total lost revenue. We also incurred $500,000 of additional storm-related lease operating expenses in each quarter, equal to our "per occurrence" insurance deductible. Just as importantly, our drilling program and facility construction activity were significantly delayed.

After the storms passed, we were faced with an important operational decision: whether or not to try to complete our planned drilling and development program for the year within what remained of the fourth quarter. Our operations team rose to the challenge. At one point we had as many as eight rigs working on EPL-operated wells and two rigs on non-operated wells. During the fourth quarter alone, 10 of the 12 new wells drilled were successful, which included 10 exploratory wells and two development wells. Our success rate on new wells for the full year 2002 totaled 12 of 15 exploratory wells and two of two development wells. That equates to an overall success rate of 82%, outstanding by any measure. The prospects we drilled came almost equally from three sources: core EPL properties held prior to the HHOC acquisition, properties acquired in the HHOC acquisition, and leasehold interests we acquired in last year's lease sale or through industry trades.

That success led to impressive operational results for the year. We replaced 130% of 2002 production from a combination of successful drilling activities and a minor amount of reserve revisions, at an average finding and development cost of $8.33 per Boe. The majority of our drilling successes occurred in the fourth quarter and will come onstream in 2003.

The reserves acquired in our 2002 purchase of HHOC replaced 157% of production at an average cost of $12.60 per Boe. There were no sales of reserves in 2002. Total reserve replacement from all sources was 287%, with an all-in reserve replacement cost of $10.66 per Boe. While 2002 was an excellent year, we believe that it is more appropriate to consider three-year average reserve replacement as a better indicator of a company's ongoing ability to add reserves economically. EPL's three-year average reserve replacement from the drill-bit and revisions averaged 118%, and from all sources including acquisitions averaged 361%. All-in reserve replacement costs over the same period averaged $7.70 per Boe, an attractive rate for a Gulf of Mexico focused company.

Year-end 2002 reserves grew 33% to 47.5 Mmboe from 35.8 Mmboe at year-end 2001. Our year-end 2002 reserves were comprised of 55% oil reserves and 45% natural gas, significantly more balanced than in the prior year when they were 71% oil, 29% natural gas.

Despite the weather related challenges we faced in 2002, production rose significantly during the year. By year-end, we had restored the majority of our curtailed production and had added new production from several drilling successes. Our exit rate averaged 20,500 Boe per day, 27% above the 2001 average and 19% above the 2002 average. Keep in mind that our 2002 exit rate did not include nine new wells that are slated to come onstream by mid-2003. I would note that our 2002 exit rate had become more weighted to gas, with 57% natural gas and 43% oil.

While we had an excellent year operationally, our 2002 financial results clearly did not reflect that success. We reported a net loss available to common stockholders of $12.1 million compared with net income of $12 million in 2001, and our discretionary cash flow fell to $60 million from $85.5 million in 2001. The loss of revenue and increased expenses from the storms, weak energy prices in the first half of the year, and a revised capital structure and additional costs associated with the HHOC acquisition, all contributed to the decline in results. Nevertheless, we maintained our financial discipline and net debt remained at 35% of total capitalization at year-end, well below our tolerance level.

Our outlook for improved financial results in 2003 is underpinned by expected growth in our production volumes, improved energy prices, and significant progress in lowering our costs on a unit of production basis. We have taken advantage of higher commodity prices and added to our production hedging positions.

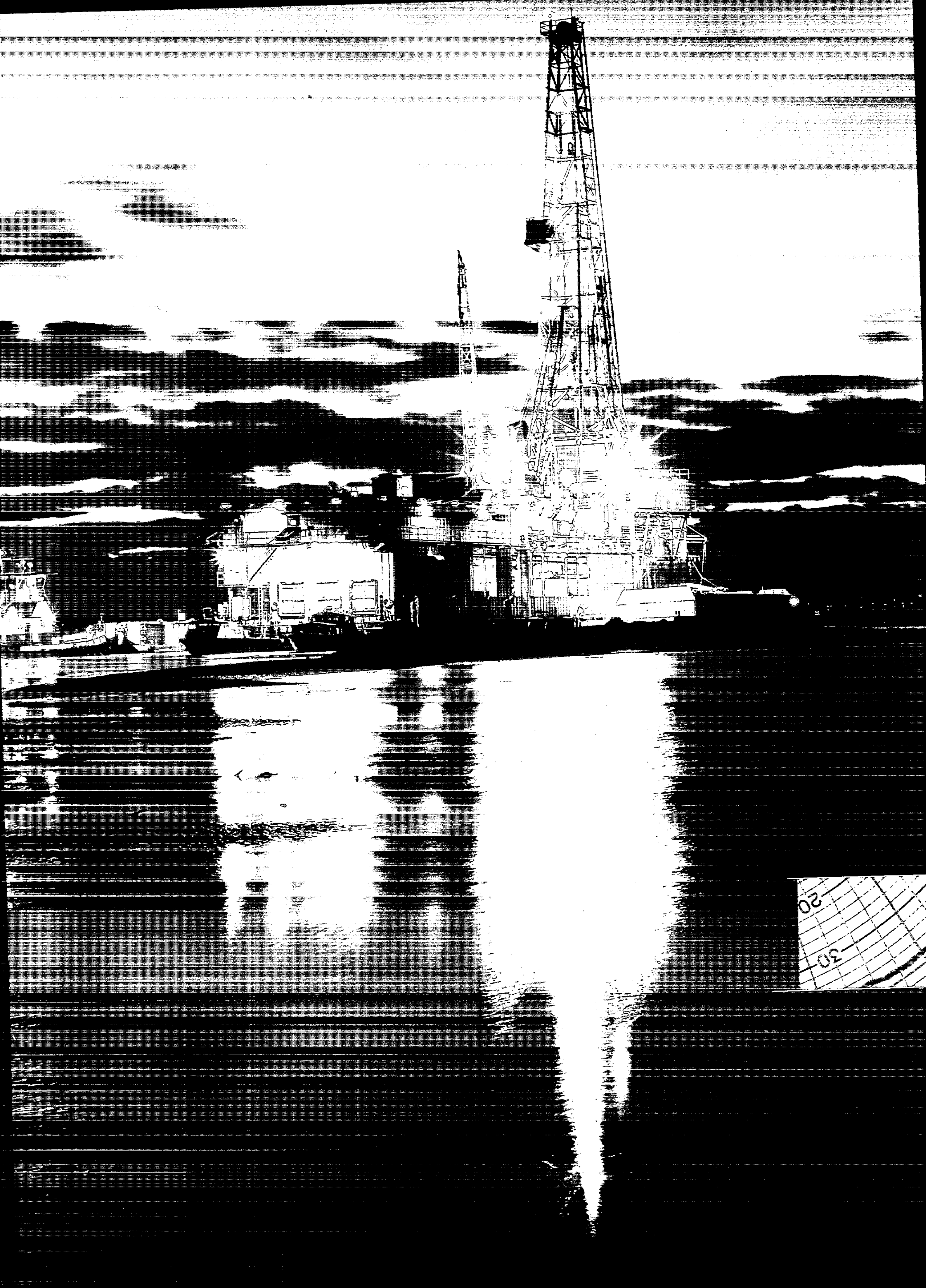
Encouraged by our operational success in 2002, our Board approved a $90 million capital budget for 2003, up 32% from $68.1 million invested in 2002. Our hedging program provides us with an attractive degree of stability in our projected 2003 cash flow to give us confidence in

proceeding with our expanded capital program. We plan to drill at least as many wells in 2003 as we did last year. We expect to invest about 65% of the budget in low risk, exploitation and development activities, 25% in moderate risk exploration and at least 10% in higher potential, higher risk drilling. A key point to be noted here is that, unlike many of our peers, EPL is prospect rich. We have an extensive inventory of drillable prospects in-house, we are generating more internally and we are being exposed to new opportunities through relationships with industry partners. Even with an expanded budget, higher commodity prices together with growing production volumes should enable us to generate free cash flow in 2003 that would allow us to accelerate our drilling plans, reduce debt or pursue acquisitions. We believe this year will provide us a number of opportunities to acquire targeted properties within our focus area.

Our accomplishments in 2002 were the result of the hard work, creativity and team effort of our employees in every single location and department within the Company. I am extremely proud of what they have achieved.

In closing, I would like to reiterate our commitments to you. We will remain focused in our niche market of the shallow to moderate depth waters of the Gulf where we have technical expertise. We will pursue only those opportunities that will allow us to achieve profitable growth and our targeted returns while maintaining strong fiscal discipline. And we will continue to adhere to the high ethical and corporate governance standards we set for ourselves when we founded the Company and will assure you that these standards meet or exceed SEC and NYSE requirements. With the continued hard work and dedication of our technical and support teams, the strength and commitment of our management team and the ongoing support of you, our shareholders, we believe the market will further reward the value creation abilities we have developed and demonstrated at EPL.

Richard A. Bachmann
Chairman, President and
Chief Executive Officer


20
30

FINANCIAL DATA

(In thousands, except per share amounts)	2002	2001	2000	1999	1998 (a)
Revenues	$ 134,031	$ 146,201	$ 103,236	$ 9,509	$ 1,966
Income (loss) from operations (b)	(6,357)	20,624	(8,721)	(835)	(311)
Net income (loss)	(8,799)	11,974	(18,684)	(2,284)	(705)
Diluted earnings (loss) per common share (c)	$ (0.44)	$ 0.44	$ (2.27)	$ (0.22)	$ (0.09)
Diluted weighted average common shares	27,467	26,920	11,160	14,247	7,427
Exploration and development expenditures	68,066	103,467	63,116	17,112	17,531
Total assets	$ 384,220	$ 242,777	$ 208,149	$ 69,276	$ 40,015
Long-term debt	103,779	25,493	100	10,150	20,000
Mandatorily redeemable preferred stock	—	—	—	56,475	—
Stockholders' equity	191,922	164,867	150,591	(3,815)	(694)

OPERATING DATA

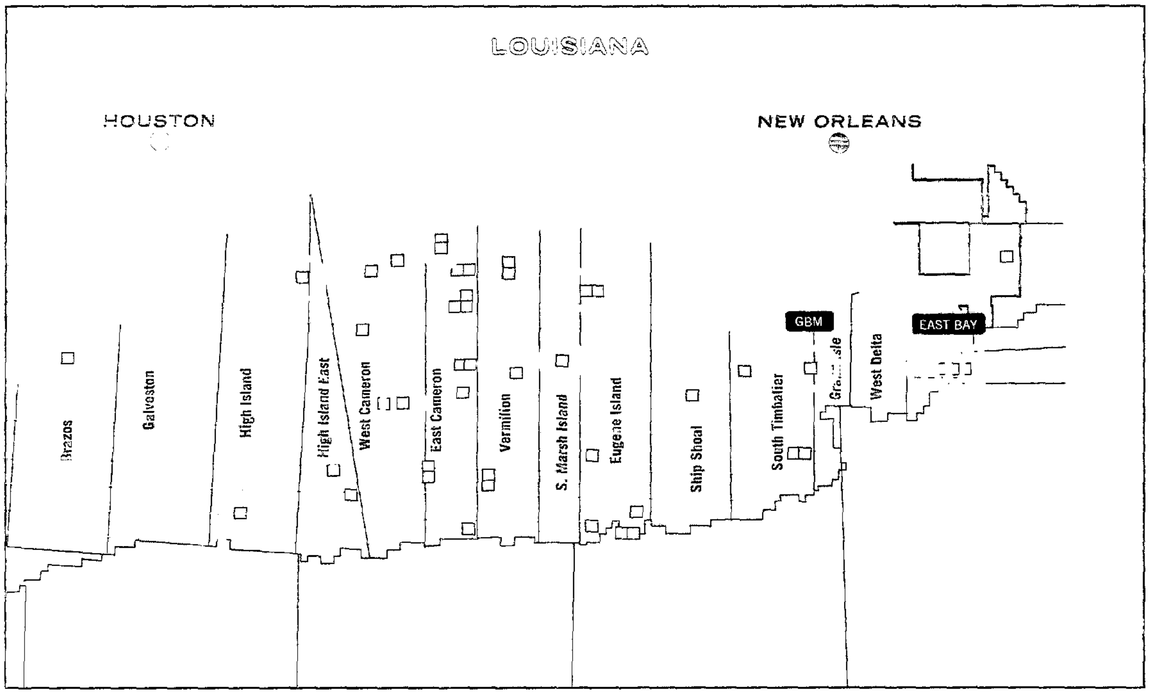
	2002	2001	2000	1999	1998 (a)
Total estimated net proved reserves:					
Oil (Mbbls)	26,353	25,462	27,521	3,824	2,861
Natural gas (Mmcf)	126,957	61,797	49,150	12,752	12,534
Total (Mboe)	47,513	35,762	35,712	5,949	4,950
Net production (per day):					
Oil (Bbls)	8,148	10,358	7,622	1,051	534
Natural gas (Mcf)	54,150	34,562	15,781	2,277	1,311
Total (Boe)	17,173	16,118	10,252	1,431	753
Average sales price:					
Oil (per Bbl)	$ 23.64	$ 23.44	$ 25.86	$ 17.39	$ 13.21
Natural gas (per Mcf)	3.23	4.40	4.98	2.17	2.20
Total (per Boe)	21.40	24.50	26.89	16.22	13.18
Present value of estimated future net revenues before income taxes (in thousands)(d)	$ 608,273	$ 129,122	$ 489,945	$ 54,819	$ 27,533
Total well projects	44	88	108	20	10
Percentage of successful well projects	77%	86%	91%	75%	100%

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

(b) The 2000 loss from operations [illegible] stock compensation charge for shares released [illegible] to management and director stockholders [illegible] non-cash charge of [illegible] for bonus shares awarded to [illegible] 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 [illegible] stockholders' equity.

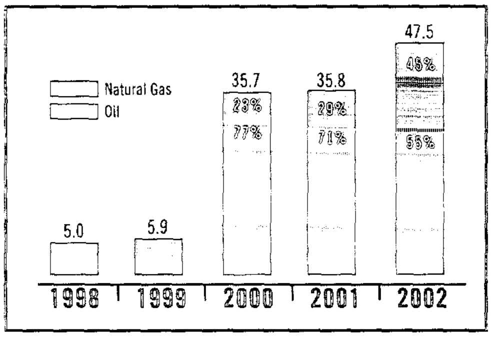
(c) Net earnings (loss) per share is computed by subtracting preferred stock dividends and accretion of discount of $3.3 million in 2002 and preferred stock dividends and accretion of issuance costs for the years ended December 31, 2000 of $6.7 million and December 31, 1999 of $0.8 million.

(d) The present value of estimated future net revenues [illegible] was prepared using constant prices [illegible]

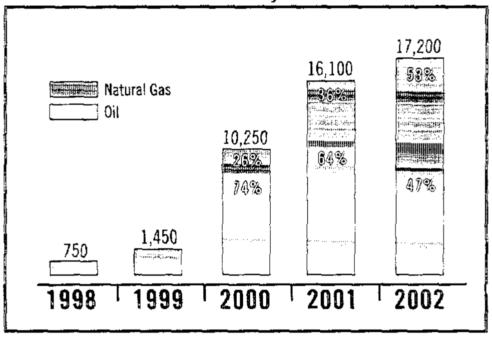


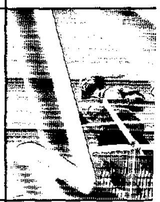
During 2002, EPL drilled 17 new wells. This included 15 exploratory wells and two development wells, 12 of which were drilled in the fourth quarter alone. We achieved exceptional success – 12 of the exploratory wells and both of the development wells were successful. Our program included a balanced mix of lower risk exploitation and development wells; moderate risk, moderate potential opportunities; and higher risk, higher potential prospects. The projects came almost equally from three sources: EPL's core properties; properties added in the HHOC acquisition; and from industry trades and the March 2002 federal lease sale. The map above highlights those successful wells, all of which were drilled in water depths of less than 500 feet.

Proved Reserves Mmboe as of 12/31



Production Boe/day



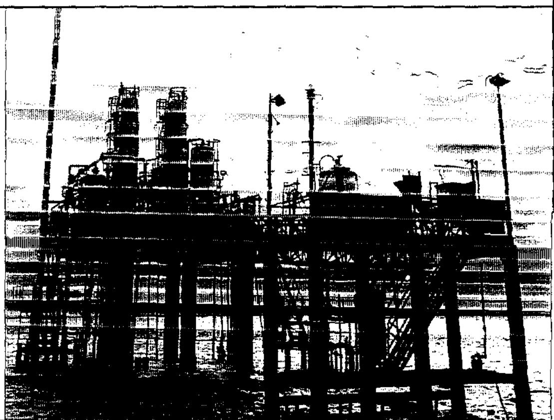


Successful Exploratory (12)

Successful Development (2)

EPL Interests

LEGEND



AN INTERVIEW

Richard A. Bachmann, Chairman, President and Chief Executive Officer speaks about people, properties and strategy.

To what do you attribute your high rate of success in 2002?

We believe we now have the ideal combination of the right people and the right properties to execute our strategy. EPL's 82% drilling success rate in 2002 was high by industry standards.

Is it repeatable?

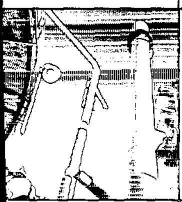
An 82% success rate is difficult to sustain year after year. However, we have an equally active drilling program planned for 2003 with a similar risk/reward profile as last year's that should enable us to grow the Company.

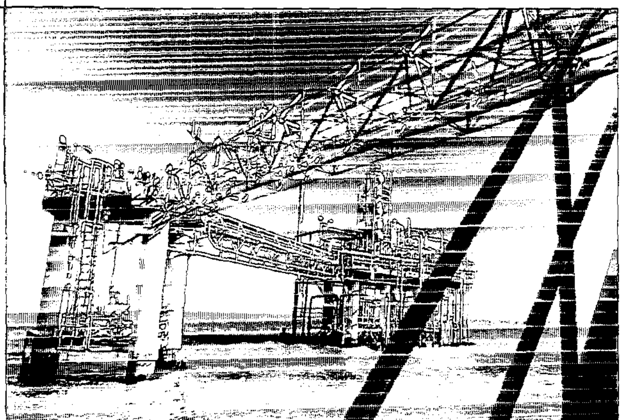
Do you have an inventory of drilling prospects beyond 2003?

Unlike many of our peer companies, EPL is prospect rich. We have a multi-year inventory of opportunities that we are constantly expanding with new, internally generated prospects as well as with prospects added through relationships with industry partners.

Can you continue to grow EPL remaining focused in the shallow waters of the Gulf of Mexico?

With internally generated drilling prospects, targeted acquisitions and new drill-to-earns, we believe we can at least triple our size and remain focused in the region. In addition, technology is opening up exciting new high potential, deeper drilling opportunities on existing producing properties.





Why have you focused on that region?

That area offers some of the best geologic conditions in the United States and good geology generates good economics. Just as importantly, that is where our technical teams have the greatest expertise.

Do you plan to acquire additional properties and add new drill-to-earns?

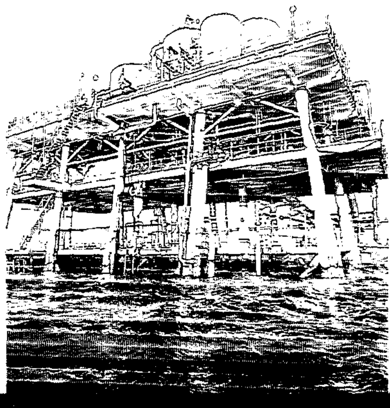
While we will continue to execute our 2003 exploration and exploitation drilling program, we will also pursue adding new strategic properties in our focus area. We are aware of a number of properties that will likely become available in 2003. We are ready to negotiate one-on-one deals to add targeted properties.

Are you pleased with the results of the HHOC acquisition?

Absolutely. It strengthened our management and technical teams, especially in the exploration area, and expanded our prospect inventory. Their reserves were primarily natural gas so the acquisition also made our reserves and production better balanced.

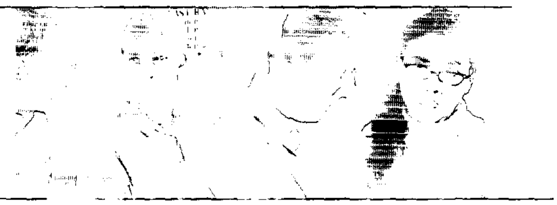
What are your long-term goals?

Our key goals include growing production and reserves; controlling our operating and overhead costs; employing capital discipline and maintaining liquidity. All of these contribute to our primary objective of achieving a return on capital that is significantly greater than that of our peer companies.

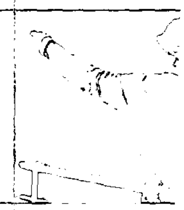


In 2002, we achieved a number of significant operational milestones. We attained an 82% success rate in the most active drilling program in our history; we replaced 130% of our production with new reserves from the drill bit; we replaced 157% of our production with new reserves added from the HHOC acquisition and we completed the integration of those properties and the HHOC staff into EPL by mid-year; we lowered our finding and development costs and reduced our lease operating expenses; we grew year-end production 27% from the prior year despite weather-related disruptions; and we expanded our portfolio of drilling opportunities and affirmed the upside potential of EPL's single largest asset, the East Bay Field.

We began the year with a capital and exploration budget of $60 to $80 million that was designed to be flexible in response to changes in commodity prices and cash flow. By year-end, we had invested a total of $68.1 million, of which $27.3 million was on our expanded exploratory drilling program; $38.9 million was on developmental drilling and facility and pipeline construction; and $1.9 million was on lease acquisitions. Our investments were allocated over a number of properties with the largest investment of $17.9 million at our East Bay Field. In addition, we invested $124.0 million in the HHOC acquisition including the assumption of their negative working capital position. The HHOC acquisition added approximately 79,850 net acres to our inventory. We also added approximately 16,600 net acres at federal and state lease sales and through industry trades during the year. The HHOC acquisition added at least 18 prospects to our drilling inventory and we expanded that portfolio throughout the year with internally generated prospects and prospects acquired from partners.



During 2002, we successfully completed 20 of 27 workovers and recompletions in addition to successfully completing 14 of 17 new drill wells. Of the 34 total successful projects, 4 were at Greater Bay Marchand and 13 were at East Bay, our core properties. This success enabled us to replace 130% of our 2002 production with new reserves from the drill bit, including a minimal amount of positive reserve revisions. The finding and development cost associated with these new reserves was $8.33 per Boe. We also replaced 157% of our production with new reserves from the HHOC acquisition. In total, we replaced 287% of 2002 production with all-in reserve replacement costs of $10.66 per Boe. Over the last three years, we have replaced an average of 118% of our production with the drill-bit and our finding and development costs have averaged $12.49 per Boe. During the same period, reserve acquisitions replaced 243% of production with an all-in reserve replacement cost of $7.70 per Boe. Since our inception, we have replaced 133% of production with drill-bit adds at an average cost of $12.00 per Boe. In that same period, reserve acquisitions replaced 253% of production with all-in reserve replacement cost of $7.55 per Boe. Our year-end 2002 reserves grew 33% to 47.5 Mmboe from the

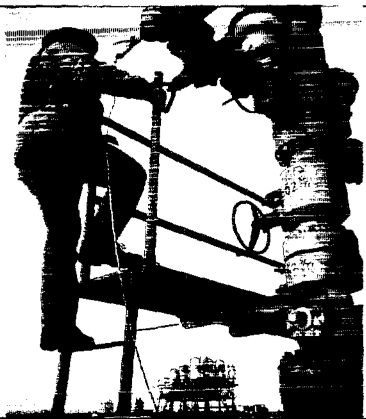


prior year-end. Our reserves have become more balanced with 45% natural gas and 55% oil. Approximately 69% of our year-end reserves were classified as proved developed.

Our successful drilling program together with the HHOC acquisition allowed us to increase our 2002 production despite the tropical weather impact. Our 2002 exit rate of 20,500 Boe per day was 27% above the 2001 average and 19% above the 2002 average. Of the 14 successful wells in our 2002 program, only five were onstream by year-end, with six scheduled to come online by March of 2003 and the balance by September of 2003. At year-end, our portfolio included 376 gross active wells and we operated 92% of our production.

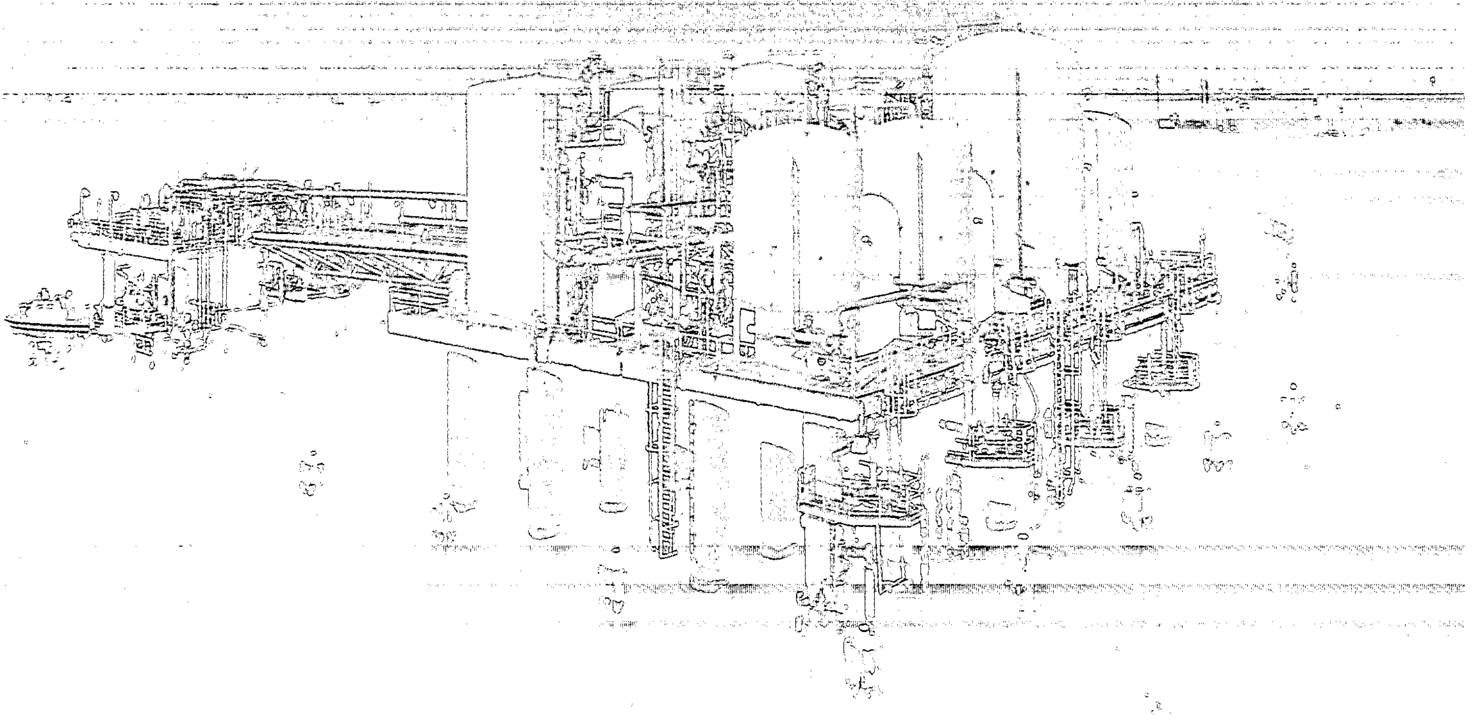
We were particularly pleased with our success at East Bay, our single largest producing property. Last year, we completed the merging of existing 3-D data on the field with a new 3-D data set and reprocessed the combined data. All four of our successful new drill wells at East Bay last year were based on that new data. Three of the wells had an exploratory component and two also had development aspects. Each of the wells encountered attractive levels of hydrocarbons. We already have six more opportunities identified at East Bay with at least two scheduled to be drilled in the first half of 2003. We believe last year's success clearly affirms the upside potential of this core property.

Our 2003 budget is currently planned at approximately $90 million, up 32% from the $68.1 million invested in 2002. This year's budget includes at least an equal number of new wells as we drilled in 2002 with a similar risk profile. We expect to allocate 65% of the funds to low risk development and exploitation activities, including further development of our 2002 successes. About 25% will be devoted to moderate risk exploration and at least 10% to high potential, higher risk drilling. We plan to fund the program with internally generated funds.



FORM 10-K

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, 2002

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:

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

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

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

The aggregate market value of the voting stock held by non-affiliates of the registrant at June 28, 2002 based on the closing price of such stock as quoted on the New York Stock Exchange on that date was $94,092,183.

As of February 28, 2003 there were 27,658,801 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 2003 Annual Meeting of Stockholders have been incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

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 Report are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this Report.

PART I

ITEMS 1 & 2. *Business and Properties*

We are an independent oil and natural gas exploration and production company focused on the shallow to moderate depth waters of the Gulf of Mexico Shelf. We concentrate on the Gulf of Mexico Shelf region because that area provides us with favorable geologic and economic conditions, including multiple reservoir formations, regional economies of scale, extensive infrastructure and comprehensive geologic databases. We believe that this region offers a balanced and expansive array of existing and prospective exploration, exploitation and development opportunities in both established productive horizons and deeper geologic formations. As of December 31, 2002, we had estimated proved reserves of approximately 127.0 Bcf of natural gas and 26.4 million barrels of oil, or an aggregate of approximately 47.5 million Boe, with a present value of estimated pre-tax future net cash flows of $608.3 million and after-tax future net cash flows of $476.9 million based upon year-end 2002 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 this team provided us with access to the operators of the Gulf of Mexico Shelf fields that became our cornerstone assets. These relationships continue to provide us with a strategic advantage as we pursue our strategy of being a consolidator of assets in the Gulf of Mexico Shelf region.

We have grown our company through a combination of exploration, exploitation and development drilling and multi-year, multi-well drill-to-earn programs, as well as strategic acquisitions of mature oil and gas fields in the Gulf of Mexico Shelf area, and in early 2002, the acquisition of Hall-Houston Oil Company ("HHOC"). We intend to continue this strategy as part of our multi-tiered focus.

On November 1, 2000, we consummated our initial public offering of 5.75 million shares of common stock, raising $80.2 million. Our common shares trade on the New York Stock Exchange under the symbol "EPL." We maintain a website at www.eplweb.com which contains information about us including links to our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all related amendments. Our web site and the information contained in it and connected to it shall not be deemed incorporated by reference into this Report on Form 10-K.

Acquisition of Hall-Houston Oil Company

On January 15, 2002, we closed the acquisition of HHOC and certain affiliated interests. At closing, we issued $38.4 million liquidation preference of newly authorized Series D Exchangeable Convertible Preferred

Stock, with a fair value of $34.7 million, discounted to effect the increasing dividend rate, $38.4 million of 11% Senior Subordinated Notes ("the Notes") due 2009 (immediately callable at par) and 574,931 shares of common stock. We also paid $5.1 million of cash, assumed HHOC's working capital deficit and issued warrants, with a fair market value of approximately $3.0 million, to purchase four million shares of common stock. Former preferred stockholders of HHOC also received the right to receive contingent consideration related to future proved reserve additions generally to come from certain exploratory prospect acreage held by HHOC as of the closing date.

The acquisition of HHOC strengthened our management team, expanded our property base, reduced our geographic concentration, and moved us to a more balanced oil and natural gas reserves and production profile. It also expanded our technical knowledge base through the addition of quality personnel and geophysical and geological data. Furthermore, the acquisition significantly improved our portfolio of exploration opportunities by adding 12 offshore exploratory blocks to complement our development and drill-to-earn portfolio. Through the acquisition, we added proved reserves of 59.1 Bcfe, of which 98% were natural gas and approximately 60% were proved developed as of the date of acquisition.

Capital Expenditures

Our capital expenditures for 2002 totaled $68.1 million for exploration and development activities. For 2003, we have budgeted exploration and development expenditures of approximately $90 million. This budget includes a mixture of lower risk development and exploitation wells, moderate risk exploration opportunities and higher risk, higher potential exploration projects.

Our Properties

At December 31, 2002, we had interests in 19 producing fields and 5 fields under development, all of which are located in the Gulf of Mexico Shelf region in water depths ranging from 3 to 476 feet. These fields fall into three focus areas which we identify as our Eastern, Central and Western areas. The Eastern area is comprised of the East Bay and Main Pass fields. The Central area is comprised of five fields, three of which are contiguous and together cover most of the Bay Marchand salt dome located in state and federal waters offshore Louisiana and two of which are in federal waters and were acquired in the acquisition of HHOC. The Western area is comprised of 12 producing fields consisting primarily of those acquired in the acquisition of HHOC and those 2002 lease acquisitions on which we drilled successful exploratory wells.

Eastern Area

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 and in water depths ranging up to 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 and the March 2002 federal lease sale, we acquired acreage that is contiguous to East Bay in several additional South Pass blocks. We are the operator of these fields and own an average 96.3% working interest. Our net revenue interest ranges from 42% to 86%. Inclusive of all lease acquisitions, our lease area covers 31,703 gross acres (30,525 net acres) of which 4,330 gross and net acres are under federal jurisdiction, while 27,373 gross acres (26,195 net acres) are under the jurisdiction of the State of Louisiana. In addition, we have 3,525 gross and net undeveloped acres under federal jurisdiction and 6,811 gross and net undeveloped acres under the jurisdiction of the State of Louisiana.

During 2002, we invested a total of $18.1 million in the drilling or sidetracking of four wells, all of which were successful, and the workover or recompletion of 14 wells, 9 of which were successful. Eastern area production accounted for approximately 52% of our net daily production during 2002.

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 has and will continue to provide improved structural and stratigraphic interpretation for additional drilling activity. Utilizing this data, we have already identified 13 new exploratory prospects and leads in and around the East Bay field. The first three of these prospects, Mesa Verde, Yosemite and Arches, were drilled in 2002. Mesa Verde was completed and placed on production in December 2002. The Yosemite prospect was drilled in December 2002, while the Arches well was completed in its deeper, proved undeveloped objective in January 2003, with both having commenced production in February 2003.

We also drilled a development well, the Whale prospect, that was a sidetrack and redrill of a well that had been drilled by the field's previous owner and abandoned due to mechanical problems. This well was completed and placed on production in November 2002.

Central Area

The focus of our Central area is the Greater Bay Marchand area 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. Also included in the Central area are two producing properties acquired in the HHOC acquisition.

During 2002, we invested a total of $2.9 million in the Central area. Our investments included the sidetracking of two wells, both of which were successful, and the workover or recompletion of 7 wells, 6 of which were successful. Production from this area accounted for approximately 25% of our net daily production in 2002.

We acquired our interests in the Greater Bay Marchand area in several separate transactions, the most significant of which follow:

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

In August 1998, we entered into a drill-to-earn agreement with ChevronTexaco Corporation ("ChevronTexaco") covering the federal outer continental shelf acreage and in May 2000, expanded the coverage to include ChevronTexaco's Louisiana state water-bottom acreage in the Bay Marchand field. 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. After the completion of the wells under this program, ChevronTexaco serves as the operator.

We currently have an agreement with ChevronTexaco, which provides for a five well drilling program and provides for a carry in favor of ChevronTexaco through capital expenditures to establish first production. These operations commenced in the fourth quarter of 2002 with the drilling, through sidetracks, of two successful exploration wells. We acquired a 40% working interest in the two wells we have drilled and intend to retain a similar interest in the three remaining wells.

Western Area

In connection with the acquisition of HHOC, we added 10 producing fields and one field under development to our property portfolio in our Western area. The properties are all located in the Gulf of Mexico Shelf area in water depths ranging from 20 to 476 feet. All of the properties that we acquired were operated by HHOC, with working interests ranging from 25% to 100%. Subsequent to the acquisition, we acquired two additional properties at the federal March lease sale and also acquired working interests in several blocks through trades with industry partners bringing our total at December 31, 2002 to 12 producing and five development fields.

During 2002 we invested a total of $47.1 million in the Western area. Our investments included the drilling or sidetracking of 11 wells, 7 of which were successful and the workover or recompletion of 6 wells, 5 of which were successful. Production in this area accounted for approximately 23% of our net daily production during 2002. The most significant exploration and development operations undertaken in the Western Gulf of Mexico region during 2002 are discussed below.

Eugene Island 247

Acquired as part of the HHOC transaction, one gas-discovery well on this field was drilled prior to the acquisition in approximately 150 feet of water and later completed and brought on-line in November 2002. At year-end, the well was producing approximately 11.6 Mmcf per day. We are the operator of this property and have a 98% working interest.

Eugene Island 27

Acquired at the March 2002 federal lease sale, we have drilled a successful exploration well in approximately 20 feet of water. We are currently considering development options with first production anticipated to occur in the third quarter 2003. We are the operator of this property and have a 100% working interest.

High Island A-538

Acquired as part of the HHOC transaction, a successful exploration well was drilled in approximately 200 feet of water and was completed in 2002. Facilities were installed and a development well was drilled and completed in January 2003. Initial production commenced in February 2003. We are the operator of this property with a 33% working interest.

High Island 72

Acquired as part of the HHOC transaction, this property had existing production from the No. 1 well. We have drilled the No. 2 well in approximately 35 feet of water and had initial production in December 2002, however the well is currently shut-in pending needed facility modifications with restored production expected in the second quarter of 2003. We are the operator of this field and have a 50% working interest in the No. 1 well and a 79% working interest in the No. 2 well.

East Cameron 9

Through two lease sales in 2001, we acquired 1,000 gross acres in East Cameron 9. In January 2002, we announced a successful discovery well, drilled in approximately 25 feet of water approximately 2.5 miles offshore in Cameron Parish, Louisiana. The well was drilled to a total depth of 14,158 feet. We are the operator of the well and own a 50% working interest. We achieved first production in June 2002. Also 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 approximately 25 feet of water.

Ship Shoal 133

We acquired an interest in this lease in 2002 and participated in the drilling of the No. 1 well in approximately 50 feet of water. We have a 33% working interest. The well was completed in the third quarter of 2002 and production commenced in January of 2003.

West Cameron 431

When acquired as part of the HHOC transaction, this property had an existing dually-completed well. A successful exploration well, the No. 3 well, was drilled and completed in approximately 100 feet of water and placed on production in December 2002. At year-end, this well was producing 5.6 Mmcf per day. We are the operator of the field and have a 70% working interest in the first well and a 100% working interest in the new well.

West Cameron 210

We obtained this lease through a partner and drilled a successful exploratory well in approximately 55 feet of water. This well was completed in November 2002 and is expected to begin production in the second quarter 2003. We are the operator of the field and have a 50% working interest.

South Marsh Island 24

We obtained a 25% working interest in this lease through a partner and participated in the drilling of a successful exploratory well in approximately 80 feet of water in late 2002. This well will be completed and is expected to begin production late in the second quarter 2003.

Oil and Natural Gas Reserves

The following table presents our estimated net proved oil and natural gas reserves and the present value of our reserves at December 31, 2002, 2001 and 2000. The December 31, 2002 estimates of proved reserves are based on reserve reports prepared by Netherland, Sewell & Associates, Inc. and Ryder Scott Company, L.P., independent petroleum engineers, and the December 31, 2001 and 2000 estimates are based on a reserve report prepared by Netherland, Sewell & Associates, Inc. Neither the present values, discounted at 10% per annum, of estimated future net cash flows before income taxes, or the standardized measure of discounted future net cash flows shown in the table are intended to represent the current market value of the estimated oil and natural gas reserves we own.

	As of December 31,		
	2002	2001	2000
Total estimated net proved reserves:			
Oil (Mbbls)	26,353	25,462	27,521
Natural gas (Mmcf)	126,957	61,797	49,150
Total (Mboe)	47,513	35,762	35,712
Net proved developed reserves(4):			
Oil (Mbbls)	21,070	22,176	25,024
Natural gas (Mmcf)	70,014	38,099	39,522
Total (Mboe)	32,739	28,526	31,611
Estimated future net revenues before income taxes (in thousands)(2)	$815,985	$168,007	$641,241
Present value of estimated future net revenues before income taxes (in thousands)(1)(2)	$608,273	$129,122	$489,945
Standardized measure of discounted future net cash flows (in thousands)(3)	$476,901	$123,377	$348,102

(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, 2002 amount was calculated using a period-end oil price of $29.53 per barrel and a period-end natural gas price of $4.83 per Mcf, while 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.

(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, 2002 were 9,916 Mbbls and 43,600 Mmcf.

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

Costs Incurred in Oil and Natural Gas Activities

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

	Years Ended December 31,		
	2002	2001	2000
		(In thousands)	
Acquisitions:			
Proved properties			
Business combinations	$116,415	$ —	$ —
Other	—	523	119,872
Unproved properties			
Business combinations	7,616	—	—
Other	1,922	1,993	288
Total acquisitions	125,953	2,516	120,160
Exploration	27,083	45,592	18,053
Development	39,061	55,882	44,775
Total costs incurred	$192,097	$103,990	$182,988

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, 2002:

	Total Productive Wells	
	Gross	Net
Oil	313	286
Natural gas	63	55
Total	376	341

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. Twenty-nine gross oil wells and seventeen gross natural gas wells have dual completions.

Acreage

The following table sets forth information as of December 31, 2002 relating to acreage held by us. Developed acreage is assigned to producing wells.

	Gross Acreage	Net Acreage
Developed:		
Eastern Area	41,591	36,772
Central Area	24,100	8,206
Western Area	65,687	46,058
Total	131,378	91,036
Undeveloped:		
Eastern Area	10,336	10,336
Central Area	403	161
Western Area	56,536	44,040
Total	67,275	54,537

Leases covering 10% of our undeveloped net acreage will expire in 2003, approximately 6% in 2004, 14% in 2005, 52% in 2006, and 18% in 2007.

Well Activity

The following table shows our well activity for the years ended December 31, 2002, 2001 and 2000. 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,					
	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	1.0	1.0	2.0	1.0	9.0	5.7
Non-Productive	—	—	—	—	2.0	1.5
Total	1.0	1.0	2.0	1.0	11.0	7.2
Exploration Wells:						
Productive	9.0	5.1	15.0	9.6	18.0	6.5
Non-Productive	3.0	0.9	5.0	4.0	1.0	0.3
Total	12.0	6.0	20.0	13.6	19.0	6.8

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

Title to Properties

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

We believe that we have satisfactory title to, or rights in, all of our producing properties. As is customary in the oil and natural gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. We investigate title 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

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

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

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

The Outer Continental Shelf Lands Act ("OCSLA"), which FERC implements as to transportation and pipeline issues, requires that all pipelines operating on or across the outer continental shelf provide open access, non-discriminatory transportation service. One of FERC's principal goals in carrying out OCSLA's mandate is to increase transparency in the market to provide producers and shippers on the 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 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

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

Regulation of Production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and 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 allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. Many states also restrict production to the market demand for oil and natural gas, and 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 Minerals Management Service ("MMS") and are required to comply with the regulations and orders promulgated by MMS under OCSLA. Among other things, we are required to obtain prior MMS approval for any exploration plans we pursue and our development and production plans for these leases. MMS regulations also establish construction requirements for production facilities located on our federal offshore leases and govern the plugging and abandonment of wells and the removal of production facilities from these leases. Under limited circumstances, MMS could require us to suspend or terminate our operations on a federal lease.

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

The failure to comply with these rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental Regulations

General. Various federal, state and local laws and regulations governing the protection of the environment, such as the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA"), the Federal Water Pollution Control Act of 1972, as amended (the "Clean Water Act"), and the Federal Clean Air Act, as amended (the "Clean Air Act"), affect our operations and costs. In particular, our exploration, development and production operations, our activities in connection with storage and transportation of oil and other hydrocarbons and our use of facilities for treating, processing or otherwise handling hydrocarbons and related wastes may be subject to regulation under these and similar state legislation. These laws and regulations:

- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- impose substantial liabilities for pollution resulting from our operations.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties or the imposition of injunctive relief. Changes in environmental laws and regulations occur regularly, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as those in the oil and natural gas industry in general. While we believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on us, there is no assurance that this trend will continue in the future.

As with the industry generally, compliance with existing regulations increases our overall cost of business. The areas affected include:

- unit production expenses primarily related to the control and limitation of air emissions and the disposal of produced water;
- capital costs to drill exploration and development wells primarily related to the management and disposal of drilling fluids and other oil and natural gas exploration wastes; and
- capital costs to construct, maintain and upgrade equipment and facilities.

Superfund. CERCLA, also known as "Superfund," imposes liability for response costs and damages to natural resources, without regard to fault or the legality of the original act, on some classes of persons that contributed to the release of a "hazardous substance" into the environment. These persons include the "owner" or "operator" of a disposal site and entities that disposed or arranged for the disposal of the hazardous substances found at the site. CERCLA also authorizes the Environmental Protection Agency ("EPA") and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our ordinary operations, we may generate waste that may fall within CERCLA's definition of a "hazardous substance." We may be jointly and severally liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these wastes have been disposed.

We currently own or lease properties that for many years have been used for the exploration and production of oil and natural gas. Although we and our predecessors have used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed or released on, under or from the properties owned or leased by us or on, under or from other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose actions with respect to the treatment and disposal or release of hydrocarbons or other wastes were not under our control. These properties and wastes disposed on these properties may be subject to CERCLA and analogous state laws. Under these laws, we could be required:

- to remove or remediate previously disposed wastes, including wastes disposed or released by prior owners or operators;
- to clean up contaminated property, including contaminated groundwater; or
- to perform remedial operations to prevent future contamination.

At this time, we do not believe that we are associated with any Superfund site and we have not been notified of any claim, liability or damages under CERCLA.

Oil Pollution Act of 1990. The Oil Pollution Act of 1990, as amended (the "OPA") and regulations thereunder impose liability on "responsible parties" for damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. Liability under OPA is strict, and under certain circumstances joint and several, and potentially unlimited. A "responsible party" includes the owner or operator of an onshore facility and the lessee or permittee of the area in which an offshore facility is located. The OPA also requires the lessee or permittee of the offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility in the amount of $35.0 million ($10.0 million if the offshore facility is located landward of the seaward boundary of a state) to cover liabilities related to an oil spill for which such person is statutorily responsible. The amount of required financial responsibility may be increased above the minimum amounts to an amount not exceeding $150.0 million depending on the risk represented by the quantity or quality of oil that is handled by the facility. We carry insurance coverage to meet these obligations, which we believe is customary for comparable companies in our industry. A failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions. We are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA's financial responsibility and other operating requirements will not have a material adverse effect on us.

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

Resource Conservation Recovery Act. RCRA, is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements, and liability for failure to meet such requirements, on a person who is either a "generator" or "transporter" of hazardous waste or an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility. At present, RCRA includes a statutory exemption that allows most oil and natural gas exploration and production waste to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA's requirements because our operations generate minimal quantities of hazardous wastes. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and natural gas exploration and production wastes from regulation as hazardous waste. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses.

Clean Water Act. The Clean Water Act imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

Safe Drinking Water Act. Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and natural gas production. The Safe Drinking Water Act of 1974, as amended establishes a regulatory framework for underground injection, with the main goal being the protection of usable aquifers. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Hazardous-waste injection well operations are strictly controlled, and certain wastes, absent an exemption, cannot be injected into underground injection control wells. In Louisiana and Texas, no underground injection may take place except as authorized by permit or rule. We currently own and operate various underground injection wells. Failure to abide by our permits could subject us to civil and/or criminal enforcement. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

Marine Protected Areas. Executive Order 13158, issued on May 26, 2000, directs federal agencies to safeguard existing Marine Protected Areas ("MPAs") in the United States and establish new MPAs. The order requires federal agencies to avoid harm to MPAs to the extent permitted by law and to the maximum extent practicable. It also directs the EPA to propose new regulations under the Clean Water Act to ensure appropriate levels of protection for the marine environment. Although at this time we cannot accurately gauges 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.

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

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operations frequently require licenses, permits and/or other governmental approvals. Several federal statutes, including

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

Lead-Based Paints. Various pieces of equipment and structures owned by us have been coated with lead-based paints as was customary in the industry at the time these pieces of equipment were fabricated and constructed. These paints may contain lead at a concentration high enough to be considered a regulated hazardous waste when removed. If we need to remove such paints in connection with maintenance or other activities and they qualify as a regulated hazardous waste, this would increase the cost of disposal. High lead levels in the paint might also require us to institute certain administrative and/or engineering controls required by the Occupational Safety and Health Act and MMS to ensure worker safety during paint removal.

Air Pollution Control. The Clean Air Act and state air pollution laws adopted to fulfill its mandates provide a framework for national, state and local efforts to protect air quality. Our operations utilize equipment that emits air pollutants subject to federal and state air pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. Air emissions associated with offshore activities are projected using a matrix and formula supplied by MMS, which has primacy from the Environmental Protection Agency for regulating such emissions.

Naturally Occurring Radioactive Materials ("NORM"). NORM are materials not covered by the Atomic Energy Act, whose radioactivity is enhanced by technological processing such as mineral extraction or processing through exploration and production conducted by the oil and natural gas industry. NORM wastes are regulated under the RCRA framework, but primary responsibility for NORM regulation has been a state function. Standards have been developed for worker protection; treatment, storage and disposal of NORM waste; management of waste piles, containers and tanks; and limitations upon the release of NORM contaminated land for unrestricted use. We believe that our operations are in material compliance with all applicable NORM standards established by the State of Louisiana.

Abandonment Costs. One of the responsibilities of owning and operating oil and natural gas properties is paying for the cost of abandonment. Effective January 1, 2003, companies are required to reflect abandonment costs as a liability on their balance sheets in the period in which it is incurred. We may incur significant abandonment costs in the future which could adversely affect our financial results.

Additional Factors Affecting Business

Exploration and Drilling Risks

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

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

Liability Risks

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

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

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

Volatility of Oil and Natural Gas Prices

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

- changes in the global supply, demand and inventories of oil;
- domestic natural gas supply, demand and inventories;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the price and quantity of foreign imports of oil;
- political conditions, including embargoes, in or affecting other oil-producing countries;

- economic and energy infrastructure disruptions caused by actual or threatened acts of war, or terrorist activities, or national security measures deployed to protect the United States from such actual or threatened acts or activities;
- economic stability of major oil and natural gas companies and the interdependence of oil and natural gas and energy trading companies;
- the level of worldwide oil and natural gas exploration and production activity;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

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

Uncertainty of Estimates of Oil and Natural Gas Reserves

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

In order to 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 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 oil or natural gas pipeline or gathering system capacity. If that were to occur, we would be unable to realize revenue from those wells until production arrangements were made to deliver to market.

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 our company.

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

During the month of December 2002, 57% 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, 2002, approximately 58% of our proved reserves were located on this property. If the actual reserves associated with this property are less than our estimated reserves, our business, financial condition or results of operations could be adversely affected.

Relatively Short Production Life for Gulf of Mexico Properties 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. All of our operations are on the Gulf of Mexico Shelf. Production from reserves in reservoirs in the Gulf of Mexico generally declines more rapidly than from reservoirs in many other producing regions of the world. As a result, our reserve replacement needs from new investments are relatively greater. Our future oil and natural gas reserves and production, and, therefore, our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

Rapid Growth May Place Significant Demands on Our Resources

We have experienced rapid growth in our operations and expect that expansion of our operations will continue. Our acquisition of HHOC generated most of our growth in 2002. Our rapid growth has placed, and our anticipated future growth will continue to place, a significant demand on our managerial, operational and financial resources due to:

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

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

Acquisition of Additional Reserves

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

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

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

Capital Requirements

In order to finance acquisitions of additional producing properties, finance the development of any discoveries made through any expanded exploratory program that might be undertaken or enter into significant drill-to-earn programs, we may need to alter or increase our capitalization substantially through the issuance of 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 Capital Partners L.P., together with its affiliates ("Evercore"), beneficially owns approximately 34% of our outstanding shares of common stock and Evercore is entitled to nominate four of our nine directors. 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. 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 offer assurance that costs will not increase again or that necessary equipment and services will be available to us at economical prices.

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

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

- the board of directors' ability to issue shares of preferred stock and determine the terms of the preferred stock without approval of common stockholders; and

- a prohibition on the right of stockholders to call meetings and a limitation on the right of stockholders to act by written consent and to present proposals or make nominations at stockholder meetings.

In addition, Delaware law imposes some restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. 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 Shelf area is highly competitive, and our success there will depend largely on our ability to attract and retain experienced geoscientists and other professional staff.

Competition

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

Significant Customers

We market substantially all of the oil and natural gas from properties we operate and from properties others operate where our interest is significant. A majority of oil production from the East Bay field is sold under a contract with Shell Trading (US) Company ("Shell") expiring December 2003, and Evergreen thereafter unless either party cancels the contract. Our oil, condensate and natural gas production is sold to a variety of purchasers, typically at market-sensitive prices. Our purchasers of oil and condensate include ChevronTexaco and Shell. Currently, our most significant purchaser of our natural gas production is Duke Energy Trading and Marketing, L.L.C. ("Duke"). We believe that the prices for liquids and natural gas are comparable to market prices in the areas where we have production. We also have a natural gas processing arrangement for our production at our Bay Marchand and East Bay fields with Dynegy Midstream Services, L.P. Of our total oil and natural gas revenues in 2002, Shell accounted for approximately 41 percent, Duke 27 percent and ChevronTexaco 11 percent.

Due to the nature of the markets for oil and natural gas, we do not believe that the loss of any one of these customers would have a material adverse effect on our financial condition or results of operation although a temporary disruption in production revenues could occur.

Employees

As of December 31, 2002, we had 132 full-time employees, including 47 geoscientists, engineers and technicians and 57 field personnel. Our employees are not represented by any labor union. We consider relations with our employees to be satisfactory and we have never experienced a work stoppage or strike.

ITEM 3. *Legal Proceedings*

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

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

None

ITEM 4A. *Executive Officers of the Registrant*

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

Name	Age	Position
Richard A. Bachmann	58	Chairman, President and Chief Executive Officer
Gary L. Hall	53	Vice Chairman
Suzanne V. Baer	55	Executive Vice President and Chief Financial Officer
Clinton W. Coldren	47	Executive Vice President and Chief Operating Officer
John H. Peper	50	Executive Vice President, General Counsel and Corporate Secretary
Bruce R. Sidner	53	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 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 33 years of financial management, investor relations and treasury experience in the energy industry. From July 1998 until March 2000, Ms. Baer had been vice president and treasurer of Burlington Resources Inc. and, from October 1997 to July 1998, was vice president and assistant treasurer of Burlington Resources. Prior to the merger of LL&E with Burlington Resources in 1997, Ms. Baer was vice president and treasurer of LL&E since 1995.

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

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

PART II

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

Our common stock is listed on the New York Stock Exchange under the symbol "EPL." The following table sets forth, for the periods indicated, the range of the high and low sales prices of our common stock as reported by the New York Stock Exchange.

	High	Low
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	8.63	5.90
Second Quarter	9.30	6.51
Third Quarter	9.00	6.40
Fourth Quarter	11.80	7.70
2003		
First Quarter (through February 28, 2003)	11.60	9.70

On February 28, 2003, the last reported sale price of our common stock on the New York Stock Exchange was $10.80 per share.

As of February 28, 2003, there were approximately 158 holders of record of our common stock.

We have not paid any cash dividends in the past on our common stock and do not intend to pay cash dividends on our common stock in the foreseeable future. We intend to retain earnings for the future operation and development of our business. Any future cash dividends to holders of common stock would depend on future earnings, capital requirements, our financial condition and other factors determined by our board of directors.

ITEM 6. *Selected Financial Data*

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

	Years Ended December 31, 2002	2001	2000	1999	January 29, 1998 (Inception) to December 31, 1998
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenue	$134,031	$ 146,201	$ 103,236	$ 9,509	$ 1,966
Income (loss) from operations(1)	(6,357)	20,624	(8,721)	(835)	(311)
Net income (loss)	$ (8,799)	$ 11,974	$ (18,684)	$ (2,284)	$ (705)
Net income (loss) available to common stockholders(2)	$(12,129)	$ 11,974	$ (25,387)	$ (3,120)	$ (705)
Basic net income (loss) per common share	$ (0.44)	$ 0.45	$ (2.27)	$ (0.22)	$ (0.09)
Diluted net income (loss) per common share	$ (0.44)	$ 0.44	$ (2.27)	$ (0.22)	$ (0.09)
Cash flows provided by (used in):					
Operating activities	$ 25,417	$ 91,847	$ 50,703	$ (4,594)	$ 8,044
Investing activities	(54,380)	(121,067)	(130,378)	(19,233)	(27,081)
Financing activities	29,079	25,871	60,742	45,457	19,689

	As of December 31, 2002	2001	2000	1999	1998
	(In thousands)				
Balance Sheet Data:					
Total assets	$384,220	$242,777	$208,149	$69,276	$40,015
Long-term debt, excluding current maturities	103,687	25,408	100	10,150	20,000
Mandatorily redeemable preferred stock	—	—	—	56,475	—
Stockholders' equity	191,922	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 discount of $3.3 million from net loss for the year ended December 31, 2002 and by subtracting preferred stock dividends and accretion of issuance costs of $6.7 million and $0.8 million for the years ended December 31, 2000 and 1999, respectively.

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

Overview

We are an independent oil and natural gas exploration and production company, incorporated in January 1998, with operations concentrated in the shallow to moderate depth waters 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.

On March 31, 2000, we acquired the 80% working interest in South Timbalier 26 that we did not previously own and subsequently, on April 20, 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.

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

We have included the results of operations from the East Bay and South Timbalier 26 acquisitions from the closing date of March 31, 2000, the South Timbalier 22, 23 and 27 from the closing date of September 7, 2000 and the HHOC acquisition from the closing date of January 15, 2002. These acquisitions have significantly affected our results of operations and production growth.

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 from year to year.

On November 1, 2000, we consummated our initial public offering of 5.75 million shares of common stock. 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 natural gas operations.

	Years Ended December 31,		
	2002	2001	2000
Net production (per day):			
Oil (Bbls)	8,148	10,358	7,622
Natural gas (Mcf)	54,150	34,562	15,781
Total (Boe)	17,173	16,118	10,252
Oil & gas revenues (in thousands):			
Oil	$ 70,311	$ 88,633	$ 72,141
Natural Gas	63,835	55,511	28,751
Total	134,146	144,144	100,892
Average sales prices(1):			
Oil (per Bbl)	$ 23.64	$ 23.44	$ 25.86
Natural gas (per Mcf)	3.23	4.40	4.98
Total (per Boe)	21.40	24.50	26.89
Average costs (per Boe):			
Lease operating expense	$ 5.49	$ 6.21	$ 6.46
Taxes, other than on earnings	1.05	1.22	1.69
Depreciation, depletion and amortization	10.29	7.97	6.82

(1) Net of the effect of hedging transactions.

Production

Crude Oil and Condensate. Our net oil production for 2002 decreased to 8,148 Bbls per day from 10,358 Bbls per day in 2001. The decrease is the result of fewer workovers/recompletions on oil wells in 2002 combined with the impact of tropical weather in the Gulf of Mexico and natural reservoir declines.

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 combined with a full year of production from the acquisitions we made in 2000, and was partially offset by natural declines from other producing wells.

Natural Gas. Our net natural gas production for 2002 increased to 54,150 Mcf per day from 34,562 Mcf per day in 2001. The increase is the result of natural gas volumes added in the acquisition of HHOC combined with new production from natural gas wells completed during the year and was partially offset by tropical weather in the Gulf of Mexico and natural reservoir declines.

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 combined with a full year of production from the acquisitions we made in 2000, and was partially offset by natural declines from other producing wells.

Realized Prices

Crude Oil and Condensate. Our average realized oil price in 2002 was $23.64 per Bbl, consistent with the average realized price of $23.44 per Bbl in 2001. Hedging activities in 2002 reduced oil price realizations by $0.51 per Bbl or 2% from the $24.15 per Bbl that would have otherwise been received. In 2001, hedging activities reduced oil price realizations by $1.10 per Bbl or 4% from the $24.54 per Bbl that would have otherwise been received.

Our average realized oil price in 2001 was $23.44 per Bbl, a decrease of 9% from an average realized price of $25.86 per Bbl in 2000. Hedging activities in 2001 reduced oil price realizations by $1.10 per Bbl or 4% from the $24.54 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 $29.66 per Bbl that would have otherwise been received.

Natural Gas. Our average realized natural gas price in 2002 was $3.23 per Mcf, a significant decrease of 27% from an average realized price of $4.40 per Mcf in 2001. Hedging activities in 2002 reduced natural gas realizations by $0.18 per Mcf from the $3.41 per Mcf that would have otherwise been received. Hedging activities in 2001 increased natural gas realizations by $0.05 per Mcf from the $4.35 per Mcf that would have otherwise been received.

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 in 2001 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.

Revenues and Net Income

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

Our oil and natural gas revenues increased to $144.1 million in 2001 from $100.9 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 lower commodity prices.

We recognized a net loss of $8.8 million in 2002 compared to net income of $12.0 million in 2001. The decrease in net income was primarily due to the decrease in oil and natural gas revenues previously discussed, combined with higher depletion, depreciation and amortization expense incurred primarily as a result of the HHOC acquisition. We recognized net income of $12.0 million in 2001 compared to a loss of $18.7 million in 2000. The following items had a significant impact on our net income or loss in 2002, 2001 and 2000 and effect the comparability of the results of operations for those years:

- In March 2002, in connection with management's plan to reduce costs and effectively combine the operations of HHOC with ours, we executed a severance plan and recorded an expense of $1.2 million.
- In December 2001, we purchased a financially-settled put swaption (the "put swaption"), which provided us with a financially-settled natural gas swap at $2.95 per Mmbtu for 30,000 Mmbtu per day for the period from February 2002 through January 2003. The put swaption also provided us the option to cancel the swap on January 15, 2002. In the fourth quarter of 2001, we recognized an expense of $1.9 million, related to the change in time value of the option portion of the contract compared to $0.5 million expensed in January 2002 related to the remaining change in time value. This expense is classified as other revenue in the consolidated statements of operations in 2002 and 2001.
- We recorded business interruption income of $3.5 million in 2001 compared to $1.8 million in 2000 as a result of the rupture of a high-pressure natural gas transfer line at our East Bay field. The rupture occurred in November 2000 and the transfer line was restored to service in February 2001. This income is classified as other revenue in the consolidated statements of operations in 2001 and 2000.
- The net loss in 2000 is attributed to one-time non-cash stock compensation charges related to the initial public offering. We 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.

Operating Expenses

Operating expenses were impacted by the following:

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

  Lease operating expense increased $12.3 million to $36.5 million in 2001. The increase was primarily attributable to a full year of operations from the acquisitions we made in 2000.

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

  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.

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

  Exploration expenditures increased $13.4 million to $15.1 million in 2001. 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.

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

  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.

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

  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.

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

  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 to employees.

Other Income and Expense

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

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.

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

The decline in revenues we experienced in 2002 in combination with the assumption of HHOC's working capital deficit significantly reduced our cash flows from operations during 2002. Cash flows from operating activities totaled $25.4 million in 2002. Our future cash flows from operations before changes in working capital will depend on our ability to maintain and increase production through our development and exploratory drilling program, as well as the prices of oil and natural gas.

Net cash of $54.4 million used in investing activities in 2002 primarily included the $10.7 million of cash paid in conjunction with the acquisition of HHOC, which is net of $1.9 million in cash received, oil and natural gas property capital and exploration expenditures of $43.0 million and lease acquisitions of $1.9 million. Exploration expenditures incurred are excluded from operating cash flows and included in investing activities. During 2002, we completed 17 drilling projects and 27 recompletion/workover projects, 34 of which were successful. During 2001, we completed 22 drilling projects and 66 recompletion/workover projects, 76 of which were successful.

We financed the amount by which our capital expenditures exceeded cash flows from operations by increasing our borrowings against our bank credit facility. Our bank credit facility, as amended on November 1, 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 is subject to redetermination based on the proved reserves of the oil and natural gas properties that serve as collateral for the bank facility as set out in the reserve report delivered to the banks each April 1 and October 1. The bank facility permits both prime rate based borrowings and London interbank offered rate ("LIBOR") borrowings plus a floating spread. The spread will float up or down based on our utilization of the bank facility. The spread can range from 1.50% to 2.25% above LIBOR and 0% to 0.75% above prime. The borrowing base under the bank facility is secured by substantially all of our assets. The bank facility contains customary events of default and requires that we satisfy various financial covenants. At February 28, 2003, we had $80 million outstanding and $20 million of credit capacity available under the bank facility. Also included in long-term debt in the consolidated balance sheet is $38.4 million of the Notes, which are due January 2009.

We have experienced and expect to continue to experience substantial working capital requirements, primarily due to our active capital expenditure program. We believe that cash flows from operations before changes in working capital will be sufficient to meet our capital requirements for at least the next twelve months and reduce borrowings under our bank facility to levels in effect at year end 2002. Availability under the bank facility will be used to balance short-term fluctuations in working capital requirements. However, additional financing may be required in the future to fund our growth.

Our 2003 capital expenditure budget is focused on exploration, exploitation and development activities on our proved properties combined with moderate and higher risk exploratory activities on undeveloped leases. We currently intend to allocate approximately 65% of our budget on an annual basis on low risk development and exploitation activities, approximately 25% to moderate risk exploration opportunities and approximately 10% to higher risk, higher potential exploration opportunities. Our capital expenditure budget for 2003 is currently approximately $90 million. The level of our capital expenditure budget is based on many factors, including results of our drilling program, oil and natural gas prices, industry conditions, participation by other working interest owners and the costs of drilling rigs and other oilfield goods and services. Should actual conditions differ materially from expectations, some projects may be accelerated or deferred and, consequently, may increase or decrease total 2003 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, 2002:

	Payments Due by Period				
	Total	1 Year	2-3 Years	4-5 Years	Thereafter
			(In thousands)		
Long-term debt	$103,779	$ 92	$65,207	$ 109	$38,371
Operating leases	17,465	2,339	4,846	4,830	5,450
	$121,244	$2,431	$70,053	$4,939	$43,821

Hedging Activities

We enter into hedging transactions with major financial institutions to reduce exposure to fluctuations in the price of oil and natural gas. We also distribute our hedging transactions to a variety of financial institutions to reduce our exposure to counterparty credit risk. Our hedging program uses financially-settled crude oil and natural gas swaps, zero-cost collars and a combination of options used to provide floor prices with varying upside price participation. Our hedges are benchmarked to the New York Mercantile Exchange ("NYMEX") West Texas Intermediate crude oil contract and Henry Hub natural gas contracts. With a financially-settled swap, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the hedged price for the transaction, and we are required to make a payment to the counterparty if the settlement price for any settlement period is above the hedged price for the transaction. With a zero-cost collar, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price of the collar, and we are required to make a payment to the counterparty if the settlement price for any settlement period is above the cap price of the collar. In some hedges, we have modified our collar to provide full upside participation after a limited non-participation range. We had the following contracts as of December 31, 2002:

Natural Gas Positions

			Volume (Mmbtu)	
Remaining Contract Term	Contract Type	Strike Price ($/Mmbtu)	Daily	Total
01/03	Swap	$2.95	30,000	930,000
02/03 - 01/04	Collar	$3.50/$5.40	10,000	3,650,000
02/03 - 01/04	Collar	$3.50/$5.25	10,000	3,650,000

Crude Oil Positions

			Volume (Bbls)	
Remaining Contract Term	Contract Type	Strike Price ($/Bbl)	Daily	Total
01/03 - 12/03	Swap	$26.36	2,000	730,000

Subsequent to December 31, 2002 we entered into the following contracts:

Natural Gas Positions

			Volume (Mmbtu)	
Remaining Contract Term	Contract Type	Strike Price ($/Mmbtu)	Daily	Total
03/03 - 06/03	Swap	$5.16	10,000	1,220,000
04/03 - 06/03	Combination options	$4.67/$6.06/$6.16	15,000	1,365,000
02/04 - 12/04	Collar	$3.50/$8.00	10,000	3,350,000

Crude Oil Positions

			Volume (Bbls)	
Remaining Contract Term	Contract Type	Strike Price ($/Bbl)	Daily	Total
01/03 - 12/03	Swap	$27.25	1,000	365,000
02/03 - 06/03	Swap	$30.72	1,000	150,000

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

Our hedged volume as of December 31, 2002 approximated 26% of our estimated production from proved reserves through the balance of the terms of the contracts.

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

Critical Accounting Policies

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

- *Successful efforts method* — 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 independent petroleum engineers. 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 us. 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 and combination options with major financial institutions. We may in the future enter into these and other types of hedging arrangements to reduce our exposure to fluctuations in the market prices of oil and natural gas. Under the provisions of Statement 133, we are required to record our derivative instruments at fair market value as either assets or liabilities in our consolidated balance sheet. The fair value recorded is an estimate based on future commodity prices available at the time of the calculation. The fair market value could differ from actual settlements if the other party to the contract defaults on its obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

New Accounting Policies

In 2001, the Financial Accounting Standards Board ("FASB") issued Statement 143, Accounting for Asset Retirement Obligations ("Statement 143"). Statement 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred, a corresponding increase in the carrying amount of the related long-lived asset and is effective for fiscal years beginning after June 15, 2002. We will adopt Statement 143 effective January 1, 2003, using the cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation. We currently record estimated costs of dismantlement, removal, site restoration and similar activities as part of our depreciation, depletion and amortization for oil and gas properties and record a separate liability for such amounts in other liabilities. The effect of Statement 143 on our results of operations and financial condition at adoption is expected to include a net increase in long-term liabilities of $14.2 million; an increase in net property, plant and equipment of $17.8 million; a cumulative effect of adoption income of $2.3 million net of deferred income taxes and a deferred tax liability of $1.3 million. Subsequent to adoption, we do not expect this standard to have a material impact on our financial position or our results of operations.

During the second quarter of 2002, the FASB issued Statement 145, Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections ("Statement 145"). This statement rescinds SFAS No. 4, Reporting Gains and Losses from Extinguishments of Debt, and requires that all gains and losses from extinguishments of debt should be classified as extraordinary items only if they meet the criteria of in APB No. 30. Applying APB No. 30 will distinguish transactions that are part of an entity's recurring operations from those that are unusual or infrequent or that meet the criteria for classification as an extraordinary item. Any gain or loss on extinguishment of debt that was classified as an extraordinary item in prior periods presented that does not meet the criteria in APB No. 30 for classification as an extraordinary item must be reclassified. We will adopt the provisions related to the rescission of SFAS No. 4 as of January 1, 2003. The adoption of Statement 145 is not expected to have an impact on our results of operations or financial position.

In June 2002, the FASB issued Statement 146, Accounting for Costs Associated with Exit or Disposal Activities ("Statement 146"). Statement 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and requires that liabilities associated with these costs be recorded at their fair value in the period in which the liability is incurred. Statement 146 will be effective for disposal activities initiated after December 31, 2002. We will adopt the provisions related to Statement 146 as of January 1, 2003; however, the adoption is not expected to have an impact on our results of operations or financial position.

In November 2002, the FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" ("FIN 45"). FIN 45 requires a company to recognize a liability for the obligations it has undertaken in issuing a guarantee. This liability would be recorded at the inception of a guarantee and would be measured at fair value. The measurement provisions of this statement apply prospectively to guarantees issued or modified after December 31, 2002. The disclosure provisions apply to financial statements for periods ending after December 15, 2002. We do not currently have guarantees that require disclosure. We will adopt the measurement provisions of this statement in the first quarter of 2003 and the adoption is not expected to have a material effect on our financial position or results of operations.

In December 2002, the FASB issued Statement 148, Accounting for Stock-Based Compensation — Transition and Disclosure ("Statement 148"). Statement 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, Statement 148 amends the disclosure requirements of Statement 123, "Accounting for Stock-Based Compensation," to require more prominent and frequent disclosures in financial statements about the effects of stock-based compensation. The transition guidance and annual disclosure provisions of Statement 148 are effective for fiscal years ending after December 15, 2002, while the interim disclosure provisions are effective for periods beginning after December 15, 2002. We are currently assessing the impact of the transition options presented in Statement 148 and adoption of the disclosure provisions required by Statement 148 are included in this Report on Form 10-K.

In January 2003, the FASB issued FASB Interpretation No. 46, "Consolidation of Variable Interest Entities" ("FIN 46"). FIN 46 requires a company to consolidated a variable interest entity if it is designated as the primary beneficiary of that entity even if the company does not have a majority of voting interest. A variable interest entity is generally defined as a entity where its equity is unable to finance its activities or where the owners of the entity lack the risk and rewards of ownership. The provisions of FIN 46 apply immediately to variable interest entities created after January 31, 2003 and to variable interest entities in which an enterprise obtains an interest after that date. The adoption of FIN 46 is not currently expected to have an effect on our financial position or results of operations when adopted.

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, 2002, $65 million of our long-term debt had variable interest rates, while the remaining long-term debt had fixed interest rates. If market interest rates average 1% higher or lower in 2003 than in 2002, interest expense on variable rate debt would increase (decrease), and loss before income taxes would increase (decrease) by approximately $0.7 million based on the total variable rate debt outstanding at December 31, 2002.

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, 2002, we had the following contracts in place:

Natural Gas Positions

			Volume (Mmbtu)	
Remaining Contract Term	Contract Type	Strike Price ($/Mmbtu)	Daily	Total
01/03	Swap	$2.95	30,000	930,000
02/03 - 01/04	Collar	$3.50/$5.40	10,000	3,650,000
02/03 - 01/04	Collar	$3.50/$5.25	10,000	3,650,000

Crude Oil Positions

			Volume (Bbls)	
Remaining Contract Term	Contract Type	Strike Price ($/Bbl)	Daily	Total
01/03 - 12/03	Swap	$26.36	2,000	730,000

Subsequent to December 31, 2002 we entered into the following contracts:

Natural Gas Positions

			Volume (Mmbtu)	
Remaining Contract Term	Contract Type	Strike Price ($/Mmbtu)	Daily	Total
03/03 - 06/03	Swap	$5.16	10,000	1,220,000
04/03 - 06/03	Combination options	$4.67/$6.06/$6.16	15,000	1,365,000
02/04 - 12/04	Collar	$3.50/$8.00	10,000	3,350,000

Crude Oil Positions

			Volume (Bbls)	
Remaining Contract Term	Contract Type	Strike Price ($/Bbl)	Daily	Total
01/03 - 12/03	Swap	$27.25	1,000	365,000
02/03 - 06/03	Swap	$30.72	1,000	150,000

Our hedged volume as of December 31, 2002 approximated 26% of our estimated production from proved reserves through the balance of the terms of the contracts. Had these contracts been terminated at December 31, 2002, we estimate the loss would have been $3.4 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, 2002, the potential change in the fair value of commodity derivative instruments assuming a 10% adverse movement in the underlying commodity price was a $4.1 million increase in the combined estimated loss.

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

GLOSSARY OF OIL AND NATURAL GAS TERMS

"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" One billion cubic feet.

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

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

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

"Mboe" One thousand barrels of oil equivalent.

"Mcf" One thousand cubic feet of natural gas.

"Mmbtu" One million British Thermal Units.

"Mmcf" One million cubic feet of natural gas.

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

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

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

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, 2002 and 2001, 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, 2002. 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, 2002 and 2001, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2002, 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 3, 2003

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
December 31, 2002 and 2001
(In thousands, except share data)

	2002	2001
ASSETS		
Current assets:		
Cash and cash equivalents	$ 116	$ —
Trade accounts receivable — net of allowance for doubtful accounts of $1,351 in 2002 and $272 in 2001	25,824	13,753
Deferred tax asset	1,221	—
Fair value of commodity derivative instruments	—	2,047
Prepaid expenses	1,868	1,459
Total current assets	29,029	17,259
Property and equipment, at cost under the successful efforts method of accounting for oil and gas properties	471,840	287,192
Less accumulated depreciation, depletion and amortization	(121,034)	(63,330)
Net property and equipment	350,806	223,862
Other assets	3,463	363
Deferred financing costs — net of accumulated amortization of $2,365 in 2002 and $1,995 in 2001	922	1,293
	$ 384,220	$242,777
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 8,869	$ 10,404
Accrued expenses	43,533	10,985
Fair value of commodity derivative instruments	3,392	—
Current maturities of long-term debt	92	85
Total current liabilities	55,886	21,474
Long-term debt	103,687	25,408
Deferred income taxes	9,033	16,782
Other	23,692	14,246
	192,298	77,910
Stockholders' equity:		
Preferred stock, $1 par value, authorized 1,700,000 shares; 382,261 issued and outstanding; aggregate liquidation value $38,226,100	35,359	—
Common stock, par value $0.01 per share. Authorized 50,000,000 shares; issued and outstanding: 2002 — 27,550,466 shares; 2001 — 26,870,757 shares	276	269
Additional paid-in capital	187,965	180,995
Accumulated other comprehensive income (loss)	(2,171)	981
Accumulated deficit	(29,507)	(17,378)
Total stockholders' equity	191,922	164,867
Commitments and contingencies		
	$ 384,220	$242,777

See accompanying notes to consolidated financial statements.

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
Years Ended December 31, 2002, 2001 and 2000
(In thousands, except per share data)

	2002	2001	2000
Revenue:			
Oil and natural gas	$134,146	$144,144	$100,892
Other	(115)	2,057	2,344
	134,031	146,201	103,236
Costs and expenses:			
Lease operating	34,400	36,543	24,241
Taxes, other than on earnings	6,572	7,190	6,327
Exploration expenditures and dry hole costs	10,735	15,141	1,703
Depreciation, depletion and amortization	64,513	46,870	25,595
General and administrative:			
Stock-based compensation	453	1,651	2,757
Severance costs	1,211	—	—
Other general and administrative	22,504	18,182	11,058
Stock-based compensation related to public offering	—	—	40,276
Total costs and expenses	140,388	125,577	111,957
Income (loss) from operations	(6,357)	20,624	(8,721)
Other income (expense):			
Interest income	107	329	596
Interest expense	(6,988)	(1,916)	(7,438)
Gain (loss) on sale of oil and gas assets	(243)	39	7,781
	(7,124)	(1,548)	939
Income (loss) before income taxes	(13,481)	19,076	(7,782)
Income taxes	4,682	(7,102)	(10,902)
Net income (loss)	(8,799)	11,974	(18,684)
Less dividends earned on preferred stock and accretion of discount and issuance costs	(3,330)	—	(6,703)
Net income (loss) available to common stockholders	$(12,129)	$ 11,974	$(25,387)
Basic earnings (loss) per share	$ (0.44)	$ 0.45	$ (2.27)
Diluted earnings (loss) per share	$ (0.44)	$ 0.44	$ (2.27)
Weighted average common shares used in computing income (loss) per share:			
Basic	27,467	26,865	11,160
Diluted	27,467	26,920	11,160

See accompanying notes to consolidated financial statements.

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
Years Ended December 31, 2002, 2001 and 2000
(In thousands)

	Preferred Stock Shares	Preferred Stock	Common Stock Shares	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income	Accumulated Deficit	Total
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
Effect of Hall-Houston acquisition	384	34,746	575	6	6,235	—	—	40,987
Stock-based compensation	—	—	93	1	618	—	—	619
Shares cancelled	—	—	(23)	—	(167)	—	—	(167)
Conversion of preferred stock	(2)	(145)	17	—	145	—	—	—
Common stock issued to 401(k) plan	—	—	9	—	84	—	—	84
Dividends on preferred stock	—	—	—	—	—	—	(2,572)	(2,572)
Accretion of discount on preferred stock	—	758	—	—	—	—	(758)	—
Comprehensive loss:								
Net loss	—	—	—	—	—	—	(8,799)	(8,799)
Fair value of commodity derivative instruments	—	—	—	—	—	(3,152)	—	(3,152)
Comprehensive loss								(11,951)
Other	—	—	8	—	55	—	—	55
Balance at December 31, 2002	382	$35,359	27,550	$ 276	$187,965	$(2,171)	$(29,507)	$191,922

See accompanying notes to consolidated financial statements.

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
Years Ended December 31, 2002, 2001 and 2000
(In thousands)

	2002	2001	2000
Cash flows from operating activities:			
Net income (loss)	$ (8,799)	$ 11,974	$ (18,684)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	64,513	46,870	25,595
(Gain) loss on sale of oil and gas assets	243	(39)	(7,781)
Amortization of deferred revenue	(3,420)	—	—
Stock-based compensation	453	1,651	43,033
Deferred income taxes	(4,653)	7,023	10,752
Exploration expenditures	5,909	13,575	1,657
Non-cash effect of derivative instruments	514	1,928	—
Amortization of deferred financing costs	370	968	1,090
Other	52	—	—
	55,182	83,950	55,662
Changes in operating assets and liabilities, net of acquisition:			
Trade accounts receivable	(4,234)	15,177	(20,960)
Prepaid expenses	154	6	(1,164)
Fair value of commodity derivative instrument	—	(2,442)	—
Other assets	(2,160)	1,354	(1,357)
Accounts payable and accrued expenses	(21,595)	(6,403)	18,264
Other liabilities	(1,930)	205	258
Net cash provided by operating activities	25,417	91,847	50,703
Cash flows used in investing activities:			
Acquisition of business, net of cash acquired	(10,661)	—	—
Property acquisitions	(1,922)	(2,516)	(119,872)
Exploration and development expenditures	(42,979)	(119,824)	(45,488)
Other property and equipment additions	(405)	(1,349)	(1,628)
Proceeds from sale of oil and gas assets	1,587	2,622	36,610
Net cash used in investing activities	(54,380)	(121,067)	(130,378)
Cash flows from financing activities:			
Bank overdraft	(808)	808	—
Deferred financing costs	—	—	(2,836)
Repayments of long-term debt	(15,541)	(5,172)	(118,050)
Proceeds from long-term debt	48,000	30,565	108,000
Net proceeds from issuance of common stock	—	—	78,681
Payment of preferred stock dividends	(2,572)	—	(5,053)
Other	—	(330)	—
Net cash provided by financing activities	29,079	25,871	60,742
Net increase (decrease) in cash and cash equivalents	116	(3,349)	(18,933)
Cash and cash equivalents at beginning of year	—	3,349	22,282
Cash and cash equivalents at end of year	$ 116	$ —	$ 3,349

See accompanying notes to consolidated financial statements.

(1) Organization

Energy Partners, Ltd. was incorporated on January 29, 1998 and is an independent oil and natural gas exploration and production company with operations concentrated in the shallow to moderate depth waters of the Gulf of Mexico Shelf. 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 natural gas producing activities. Costs to acquire mineral interests in oil and natural gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, and geological and geophysical costs are expensed.

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

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

The estimated costs of dismantling and abandoning offshore oil and natural 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, 2002, such costs are expected to be approximately $67.2 million. To date, $22.7 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) Deferred Financing Costs

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

(e) Earnings Per Share

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

(f) Revenue Recognition

The Company uses the entitlement method for recording natural gas sales revenue. Under this method of accounting, revenue is recorded based on the Company's net working interest in field production. Deliveries of natural gas in excess of the Company's working interest are recorded as liabilities and under-deliveries are recorded as receivables. At December 31, 2002 and 2001 the Company had natural gas imbalance receivables of $1.3 million and $0.2 million, respectively and liabilities of $0.5 million and none, respectively.

(g) 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, 2002 and 2001, interest-bearing cash equivalents were approximately $4.4 million and $2.1 million, respectively. Exploration expenditures incurred are excluded from operating cash flows and included in investing activities.

(h) Hedging Activities

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

(i) Stock-based Compensation

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

	2002	2001	2000
Net income (loss) available to common stockholders:			
As reported	$ (8,799)	$ 11,974	$(25,387)
Pro forma	$(11,364)	$ 10,685	$(25,575)
Basic earnings (loss) per share:			
As reported	$ (0.44)	$ 0.45	$ (2.27)
Pro forma	$ (0.53)	$ 0.40	$ (2.29)
Diluted earnings (loss) per share:			
As reported	$ (0.44)	$ 0.44	$ (2.27)
Pro forma	$ (0.53)	$ 0.40	$ (2.29)
Average fair value of grants during the year	$ 2.72	$ 3.47	$ 4.68
Black-Scholes option pricing model assumptions:			
Risk free interest rate	4.5%	4.5%	5.0%
Expected life (years)	5	2.5 to 5	2.5 to 7
Volatility	35.0%	35.0%	41.0%
Dividend yield	—	—	—
Stock-based employee compensation cost, net of tax, included in net income (loss) as reported	$ 257	$ 749	$ 1,049

(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 2002.

(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 9, 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) 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 9, 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, Energy Income Fund, L.P. (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 discount on arriving at income available to common stockholders was $3.3 million for the year ended December 31, 2002 and the effect of preferred stock dividends and accretion of issuance costs on arriving at income available to common stockholders for the years ended December 31, 2001 and 2000 was none and $6.7 million, respectively.

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, warrants and stock options used in computing diluted earnings per share was 54,976 in 2001 and none in 2002 and 2000, 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.

(5) Supplemental Cash Flow Information

The following is supplemental cash flow information:

	Years Ended December 31,		
	2002	2001	2000
	(In thousands)		
Interest paid, net of amounts capitalized	$4,616	$842	$ 6,534
Income taxes paid, net of refunds	$ (29)	$ 79	$ 150

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

	Years Ended December 31,		
	2002	2001	2000
	(In thousands)		
Dividends earned on preferred stock	$ —	$ —	$ 6,340
Accretion of preferred stock	$ 758	$ —	$ —
Conversion of preferred stock	$ 145	$ —	$58,079
Conversion of warrants	$ —	$ 5	$ —

(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 for approximately $72.3 million. The entire purchase price for both acquisitions was financed by our bank facility and 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 results of operations for each transaction have been included from the respective acquisition or sale date.

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

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

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

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

The unaudited pro-forma results of operations, assuming that the HHOC acquisition occurred on January 1, 2001, is as follows (in thousands, except per share amounts):

	2001 (Unaudited)
Pro forma:	
Revenue	$175,481
Loss from operations	(5,541)
Net loss	(3,144)
Basic loss per common share	$ (0.24)
Diluted loss per common share	$ (0.24)

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

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

(7) Property and Equipment

The following is a summary of property and equipment at December 31, 2002 and 2001:

	2002	2001
	(In thousands)	
Proved oil and natural gas properties	$ 458,610	$281,577
Unproved oil and natural gas properties	9,180	2,273
Other	4,050	3,342
	471,840	287,192
Less accumulated depreciation, depletion and amortization	(121,034)	(63,330)
Net property and equipment	$ 350,806	$223,862

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

(8) 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 of South Timbalier 26 and East Bay Field, as 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.

The bank facility, as amended on November 1, 2002, provides for a $100 million borrowing base that is subject to redetermination based on the proved reserves of the oil and gas properties that serve as collateral for the bank facility as set out in the reserve report delivered to the banks each April 1 and October 1. The bank facility is available through March 30, 2005 with interest permitted at both prime rate based borrowings and London interbank borrowing rate (LIBOR) borrowings plus a floating spread. The spread will float up or down based on our utilization of the bank facility. The spread can range from 0% to 0.75% above prime and 1.5% to 2.25% above LIBOR. Indebtedness under the bank facility is secured by substantially all of the assets of the Company. The weighted average interest rate at December 31, 2002 and 2001 was 3.18% and 3.41%, respectively. 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, 2002.

In addition, as stated in note 6, 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 bank facility, the proceeds of such offering will be used to prepay the principal amount of the Notes plus accrued interest.

Total long-term debt outstanding at December 31, 2002 and 2001 were as follows:

	2002	2001
	(in thousands)	
Bank facility, interest rate based on prime and LIBOR borrowing rates plus a floating spread payable March 30, 2005, with weighted average interest on December 31, 2002 of 3.18%	$ 65,000	$25,000
The Notes, annual interest of 11%, due January 15, 2009	38,371	—
Financing note payable, annual interest of 7.99%, equal monthly payments, maturing February 2006	408	493
	103,779	25,493
Less: Current maturities	92	85
	$103,687	$25,408

Maturities of long-term debt as of December 31, 2002 were as follows (in thousands):

2003	$ 92
2004	99
2005	65,108
2006	109
2007	—
Thereafter	38,371
	$103,779

On April 15, 1998, the Company entered into a $20.0 million financing agreement with EIF. On February 10, 1999, the financing agreement was amended to increase the facility to $25.0 million. On

November 17, 1999, the Company used $15.0 million of the proceeds from the Preferred Stock transaction, discussed in note 9, 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.

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 9. 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.

(9) Preferred Stock

In 1999, the Company authorized 1,700,000 shares of redeemable preferred stock (Preferred Stock) having a par value of $1.00 per share, of which 1,550,000 shares were designated as Series A and Series B Redeemable Cumulative Convertible Preferred Stock and Series C Redeemable Cumulative Preferred Stock. The remaining 150,000 shares were 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. 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.

In connection with the acquisition of HHOC, in January 2002, the series A, B and C classes were returned to undesignated and the Board of Directors of the Company designated 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 June 30 and December 31 of each year as follows:

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

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

(10) Significant Customers

The Company had oil and natural gas sales to three customers accounting for approximately 41 percent, 27 percent, and 11 percent, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2002. The Company had oil and natural gas sales to three customers accounting for approximately 38 percent, 37 percent and 15 percent, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2001. The Company had oil and natural gas sales to two customers accounting for 53 percent and 18 percent, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2000.

(11) 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 also uses financially-settled crude oil and natural gas swaps, zero-cost collars and options used to provide floor prices with varying upside price participation.

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

With a financially-settled swap, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the hedged price for the transaction, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the hedged price for the transaction. With a zero-cost collar, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price of the collar, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the cap price for the collar.

The Company had the following hedging contracts as of December 31, 2002:

Natural Gas Positions

Remaining Contract Term	Contract Type	Strike Price ($/Mmbtu)	Volume (Mmbtu) Daily	Volume (Mmbtu) Total
01/03	Swap	$2.95	30,000	930,000
02/03 - 01/04	Collar	$3.50/$5.40	10,000	3,650,000
02/03 - 01/04	Collar	$3.50/$5.25	10,000	3,650,000

Crude Oil Positions

Remaining Contract Term	Contract Type	Strike Price ($/Bbl)	Volume (Bbls) Daily	Volume (Bbls) Total
01/03 - 12/03	Swap	$26.36	2,000	730,000

Subsequent to December 31, 2002 we entered into the following contracts:

Natural Gas Positions

Remaining Contract Term	Contract Type	Strike Price ($/Mmbtu)	Volume (Mmbtu) Daily	Volume (Mmbtu) Total
03/03 - 06/03	Swap	$5.16	10,000	1,220,000
04/03 - 06/03	Combination options	$4.67/$6.06/$6.16	15,000	1,365,000
02/04 - 12/04	Collar	$3.50/$8.00	10,000	3,350,000

Crude Oil Positions

Remaining Contract Term	Contract Type	Strike Price ($/Bbl)	Volume (Bbls) Daily	Volume (Bbls) Total
01/03 - 12/03	Swap	$27.25	1,000	365,000
02/03 - 06/03	Swap	$30.72	1,000	150,000

For the years ended December 31, 2002, 2001 and 2000, hedging activities reduced oil and gas revenues by $5.0, $3.5 and $10.6 million, respectively.

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 million in accumulated other comprehensive income at December 31, 2001 related to hedging activities. During 2002, losses of $3.2 million, net of tax, were transferred from accumulated other comprehensive income (loss), and the fair value of outstanding derivative instruments decreased by $10.0 million ($6.4 million net of tax) to a liability of $3.4 million ($2.2 million net of tax) resulting in an ending balance of $2.2 million related to hedging activities in accumulated other comprehensive income (loss) at December 31, 2002. Based upon current prices, the Company expects to transfer approximately $3.2 million of net deferred losses in accumulated other comprehensive income (loss) as of December 31, 2002 to earnings during 2003 when the forecasted transactions actually occur.

(12) Fair Value

The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2002 and 2001. The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties. The table excludes cash and cash equivalents, trade accounts receivable, noncurrent assets, trade accounts payable and accrued expenses and derivative instruments, all of which had fair values approximating carrying amounts. The fair value of current and long-term debt is estimated based on current rates offered the Company for debt of the same maturities. The Company has off-balance sheet exposures relating to certain financial guarantees and letters of credit. The fair value of these, which represents fees associated with obtaining the instruments, was nominal.

	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Financial liabilities:				
Current and long-term debt:				
Bank facility	$65,000	$65,000	$25,000	$25,000
The Notes	38,371	41,420	—	—
Financing note payable	408	408	493	493

(13) Income Taxes

Components of income tax expense (benefit) for the years ended December 31, 2002, 2001 and 2000 are as follows:

	Current	Deferred	Total
	(In thousands)		
2002:			
Federal	$ (29)	$ (4,393)	$ (4,422)
State	—	(260)	(260)
	$ (29)	$ (4,653)	$ (4,682)
2001:			
Federal	$ 79	$ 6,628	$ 6,707
State	—	395	395
	$ 79	$ 7,023	$ 7,102
2000:			
Federal	$150	$10,230	$10,380
State	—	522	522
	$150	$10,752	$10,902

The reasons for the differences between the effective tax rates and the "expected" corporate federal income tax rate of 35% is as follows:

	Percentage of Pretax Earnings		
	2002	2001	2000
Expected tax rate	(34.0)%	34.0%	(34.0)%
Stock-based compensation	1.0	1.1	168.3
State taxes	(1.9)	2.1	6.7
Other	0.2	—	(0.9)
	(34.7)%	37.2%	140.1%

The tax effects of temporary differences that give rise to significant portions of the current tax asset and net deferred tax liability at December 31, 2002 and 2001 are presented below:

	2002	2001
	(In thousands)	
Current tax asset:		
Fair value of commodity derivative instruments	$ 1,221	$ —
Deferred tax assets:		
Restricted stock awards and options	$ 1,074	$ 1,376
Federal and state net operating loss carryforwards	17,358	8,399
Fair value of commodity derivative instruments	—	143
Other	220	197
Deferred tax liability:		
Property, plant and equipment, principally due to differences in depreciation	(27,685)	(26,897)
Net noncurrent deferred tax liability	$ (9,033)	$(16,782)

At December 31, 2002, the Company had net operating loss carryforwards of approximately $48.2 million, which are available to reduce future federal taxable income. The net operating loss carryforwards begin expiring in the years 2018 through 2022. Although realization is not assured, management believes it is more likely than not that all of the deferred tax assets will be realized through future earnings, reversal of taxable temporary differences and tax planning strategies. As a result, no valuation allowance has been provided.

(14) Employee Benefit Plans

The Company has outstanding stock options and restricted stock awards under the Amended and Restated 2000 Long Term Stock Incentive Plan. The amended plan was approved by stockholders on May 9, 2002. 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 Compensation Committee is authorized to select the employees of the Company and its subsidiaries and affiliates who will receive awards, to determine the types of awards to be granted to each person, and to establish the terms of each award. The total number of shares that may be issued under the plan is 4,800,000 and includes the grant of options and restricted stock discussed below.

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 vested 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 in April 2001, 150,000 shares at $8.82 per share in April 2002 and the remaining shares at $10.14 in April 2003. The grant date fair value of the restricted stock and options was $17.00.

The Company issued 32,750 and 60,240 shares of common stock as restricted stock awards to certain employees and officers in two separate grants during 2002. The restricted shares in the first grant had a grant date fair value of $7.98 per share and vest January 17, 2004. The restricted shares in the second grant had a grant date fair value of $8.30 and vest January 17, 2005.

The Company has recognized non-cash compensation expense of $0.5 million, $1.7 million and $2.8 million in 2002, 2001 and 2000, respectively, related to the restricted stock and stock option grants. At December 31, 2002, 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 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, 2002 and 2001 are as follows:

	2002		2001	
	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
Outstanding at beginning of year	1,094,282	$10.76	568,097	$10.77
Granted	1,110,426	$ 7.96	585,808	$10.93
Exercised	—	$ —	—	$ —
Forfeited	(206,743)	$ 9.85	(59,623)	$12.57
Outstanding at end of year	1,997,965	$ 9.30	1,094,282	$10.76
Exercisable at end of year	551,349	$10.16	253,194	$10.15
Available for future grants	2,869,045		1,782,848	

A summary of information regarding stock options outstanding at December 31, 2002 is as follows:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Shares	Remaining Contractual Life	Weighted Average Price	Shares	Weighted Average Price
$7.10 - $8.82	1,310,176	7.8 years	$ 8.02	328,000	$ 8.26
$10.14 - $15.00	687,789	7.8 years	$11.72	223,349	$12.95

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

(15) 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):

2003	$ 2,339
2004	2,453
2005	2,393
2006	2,871
2007	1,959
Thereafter	5,450
	$17,465

Rent expense for the years ended December 31, 2002, 2001 and 2000 was $3.3 million, $1.8 million and $0.9 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 deposits are not required to be made for fiscal year 2004 and are to resume January 1, 2005, however, beginning December 31, 2003 the minimum balance in the trust must be maintained at $6.0 million until such time that the remaining abandonment obligation is less than that amount. Therefore if funds are drawn to pay for ongoing abandonment activities, deposits may be necessary. These deposits are classified as other assets in the accompanying consolidated balance sheets.

The Company has agreed to purchase $1.7 million, $1.5 million and $0.9 million of seismic-related services during the years ended December 31, 2003, 2004 and 2005, respectively. In addition to the above commitments, during 2002 the Company entered into a contract to purchase $5.1 million of additional seismic-related services, which can be purchased at anytime on or before February 28, 2005. During 2002 the Company paid $0.5 million for seismic-related services pertaining to this contract and has a future commitment of $4.6 million under this contract.

In February 2003, the Company settled a lawsuit filed in 2001 for $2 million. The Company expects a portion of the settlement to be reimbursed by its insurance carriers, however; at this time the amount of any reimbursement cannot be estimated and is not reflected in the consolidated balance sheets or statements of operations.

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.

(16) 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 oilfield equipment and services to the Company. The Company incurred gross costs, both capital and lease operating on behalf of itself and its working interest partners, from this service provider of approximately $4.0 million, $4.2 million and $3.9 million in 2002, 2001 and 2000, respectively. Loss of this service provider would not have a material adverse effect on the operations of the Company.

Pursuant to the Company's stockholder agreement with Evercore, the Company paid an affiliate of Evercore a monitoring fee of $250,000 for each of the years 2002, 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 paid $0.4 million for these services in 2002.

Certain officers and their affiliates that held interests prior to the HHOC transaction continue to be royalty and working interest owners in individual properties acquired from HHOC and operated by the Company. The officers and their affiliates are billed for and pay their proportionate share of drilling and operating costs in the normal course of business.

(17) Interim Financial Information (Unaudited)

The following is a summary of consolidated unaudited interim financial information for the years ended December 31, 2002 and 2001 (in thousands, except per share data):

	Three Months Ended			
	March 31	June 30	Sept. 30	Dec. 31
2002				
Revenues	$29,125	$36,863	$33,678	$34,365
Costs and expenses	36,646	34,237	35,829	33,676
Income (loss) from operations	(7,521)	2,626	(2,151)	689
Net income (loss)	(5,814)	446	(2,556)	(875)
Net loss available to common stockholders	(6,538)	(421)	(3,432)	(1,738)
Loss per share:				
Basic	$ (0.24)	$ (0.02)	$ (0.12)	$ (0.06)
Diluted	(0.24)	(0.02)	(0.12)	(0.06)

	Three Months Ended			
	March 31	June 30	Sept. 30	Dec. 31
2001				
Revenues	$49,983	$37,266	$33,734	$25,218
Costs and expenses	27,671	31,664	36,317	29,925
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)

(18) New Accounting Policies

In 2001, the Financial Accounting Standards Board (FASB) issued Statement 143, Accounting for Asset Retirement Obligations (Statement 143). Statement 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred, a corresponding increase in the carrying amount of the related long-lived asset and is effective for fiscal years beginning after June 15, 2002. The Company will adopt Statement 143 effective January 1, 2003, using the cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation. The Company currently records estimated costs of dismantlement, removal, site restoration and similar activities as part of its depreciation, depletion and amortization for oil and gas properties and records a separate liability for such amounts in other liabilities. The effect of Statement 143 on the Company's results of operations and financial condition at adoption is expected to include a net increase in long-term liabilities of $14.2 million; an increase in net property, plant and equipment of $17.8 million; a cumulative effect of adoption income of $2.3 million net of deferred income taxes and a deferred tax liability of $1.3 million. Subsequent to adoption, the Company does not expect this standard to have a material impact on the Company's financial position or its results of operations.

During the second quarter of 2002, the FASB issued Statement 145, Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections (Statement 145). This statement rescinds SFAS No. 4, Reporting Gains and Losses from Extinguishments of Debt, and requires that all gains and losses from extinguishments of debt should be classified as extraordinary items only if they meet the criteria of APB No. 30. Applying APB No. 30 will distinguish transactions that are part of an entity's recurring operations from those that are unusual or infrequent or that meet the criteria for classification as an extraordinary item. Any gain or loss on extinguishment of debt that was classified as an extraordinary item in prior periods presented that does not meet the criteria in APB No. 30 for classification as an extraordinary item must be reclassified. The Company will adopt the provisions related to the rescission of SFAS No. 4 as of January 1, 2003. The adoption of Statement 145 is not expected to have an impact on the results of operations or financial position of the Company.

In June 2002, the FASB issued Statement 146, Accounting for Costs Associated with Exit or Disposal Activities (Statement 146). Statement 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and requires that liabilities associated with these costs be recorded at their fair value in the period in which the liability is incurred. Statement 146 will be effective for disposal activities initiated after December 31, 2002. The Company will adopt the provisions related to Statement 146 as of January 1, 2003; however, the adoption is not expected to have an impact on the results of operations or financial position.

In November 2002, the FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 requires a company to recognize a liability for the obligations it has undertaken in issuing a guarantee. This liability would be recorded at the inception of a guarantee and would be measured at fair value. The measurement provisions of this statement apply prospectively to guarantees issued or modified after December 31, 2002. The disclosure provisions apply to financial statements for periods ending after December 15, 2002. The Company does not currently have guarantees that require disclosure. The Company will adopt the measurement provisions of this statement in the first quarter of 2003 and the adoptions is not expected to have a material effect on its financial position or results of operations.

In December 2002, the FASB issued Statement 148, Accounting for Stock-Based Compensation — Transition and Disclosure (Statement 148). Statement 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, Statement 148 amends the disclosure requirements of Statement 123, "Accounting for Stock-Based Compensation," to require more prominent and frequent disclosures in financial statements about the effects of stock-based compensation. The transition guidance and annual disclosure provisions of Statement 148 are effective for fiscal years ending after December 15, 2002, while the interim disclosure provisions are effective for periods beginning after December 15, 2002. The Company is currently assessing the impact of the transition options presented in Statement 148 and adoption of the disclosure provisions required by Statement 148 are included in note 2.

In January 2003, the FASB issued FASB Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46). FIN 46 requires a company to consolidated a variable interest entity if it is designated as the primary beneficiary of that entity even if the company does not have a majority of voting interest. A variable interest entity is generally defined as a entity where its equity is unable to finance its activities or where the owners of the entity lack the risk and rewards of ownership. The provisions of FIN 46 apply immediately to variable interest entities created after January 31, 2003 and to variable interest entities in which an enterprise obtains an interest after that date. The adoption of FIN 46 is not currently expected to have an effect on the Company's financial position or results of operations when adopted.

(19) Supplementary Oil and Natural 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, 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
Purchases of reserves in place	223	57,728
Extensions, discoveries and other additions	2,117	32,492
Revisions	1,525	(5,295)
Production	(2,974)	(19,765)
December 31, 2002	26,353	126,957
Proved-developed reserves:		
December 31, 2000	25,024	39,522
December 31, 2001	22,176	38,099
December 31, 2002	21,070	70,014

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

	2002	2001
	(In thousands)	
Proved properties	$ 458,610	$281,577
Unproved properties	9,180	2,273
Accumulated depreciation, depletion and amortization	(118,976)	(61,981)
Net capitalized costs	$ 348,814	$221,869

Costs incurred for oil and natural gas property acquisition, exploration and development activities for the years ended December 31, 2002, 2001 and 2000 are as follows:

	2002	2001	2000
		(In thousands)	
Acquisitions:			
Proved properties			
Business combinations	$116,415	$ —	$ —
Other	—	523	119,872
Unproved properties			
Business combinations	7,616	—	—
Other	1,922	1,993	288
Total acquisitions	125,953	2,516	120,160
Exploration	27,083	45,592	18,053
Development	39,061	55,882	44,775
Total costs incurred	$192,097	$103,990	$182,988

Standardized Measure of Discounted Future Net Cash Flows Relating to Reserves

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

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

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

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

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

	2002	2001	2000
		(In thousands)	
Future cash inflows	$1,392,062	$ 630,941	$1,200,880
Future production costs	(355,131)	(293,945)	(391,698)
Future development and abandonment costs	(220,946)	(168,989)	(167,941)
Future income tax expense	(183,377)	(4,688)	(183,901)
Future net cash flows after income taxes	632,608	163,319	457,340
10% annual discount for estimated timing of cash flows	155,707	(39,942)	(109,238)
Standardized measure of discounted future net cash flows	$ 476,901	$ 123,377	$ 348,102

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved oil and natural gas reserves for the years ended December 31, 2002, 2001 and 2000 is as follows:

	2002	2001	2000
		(In thousands)	
Beginning of the period	$ 123,377	$ 348,102	$ 47,177
Sales and transfers of oil and natural gas produced, net of production costs	(93,174)	(100,411)	(70,324)
Net changes in prices and production costs	247,642	(349,126)	58,169
Extensions, discoveries and improved recoveries, net of future production costs	131,796	49,217	23,992
Revision of quantity estimates	9,927	(12,619)	—
Previously estimated development costs incurred during the period	32,189	10,861	7,341
Purchase and sales of reserves in place	179,772	637	419,376
Changes in estimated future development costs	(19,403)	(20,014)	(8,910)
Changes in production rates (timing) and other	(22,510)	11,638	—
Accretion of discount	12,912	48,995	5,482
Net change in income taxes	(125,627)	136,097	(134,201)
Net (decrease) increase	353,524	(224,725)	300,925
End of period	$ 476,901	$ 123,377	$ 348,102

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2002 was based on period-end prices of $4.83 per Mcf for natural gas and $29.53 per barrel for crude oil. The December 31, 2001 computation was based on period-end prices of $2.71 per Mcf for natural gas and $18.21 per barrel for crude oil. Spot prices as of February 26, 2003 were $8.79 per Mmbtu for natural gas and $34.50 per barrel for crude oil before adjustment for lease quality, transportation fees and price differentials.

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

None.

PART III

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

For information required by Item 10 regarding our directors and executive officers, see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on May 6, 2003, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference, and "Part I — Item 4A. Executive Officers".

ITEM 11. *Executive Compensation*

For information required by Item 11 see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on May 6, 2003, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

ITEM 12. *Security Ownership of Certain Beneficial Owners and Management*

Except as set forth below, for the information required by Item 12 see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on May 6, 2003, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2002, with respect to compensation plans under which our equity securities are authorized for issuance.

	Number of Securities to be Issued upon Exercise of Outstanding Options	Weighted Average Exercise Price of Outstanding Options	Number of Securities Remaining Available for Future Grant
Equity compensation plans approved by stockholders	1,997,965	$9.30	2,869,045
Equity compensation plans not approved by stockholders	—	—	—

See note 14 to our consolidated financial statements for further information regarding the significant features of the above plans.

ITEM 13. *Certain Relationships and Related Transactions*

For information required by Item 13 see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on May 6, 2003, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

ITEM 14. *Controls and Procedures*

Within 90 days prior to the date of this report, our Chief Executive Officer and Chief Financial Officer completed an evaluation of our disclosure controls and procedures (as defined in Rules 13a-14(c) and 15d-14(c) of the Securities and Exchange Act of 1934, as amended). Based on this evaluation, our Chief Executive Officer and Chief Financial Officer believe that as of the date of the evaluation our disclosure controls and procedures are effective.

There were no significant changes (including corrective action with regard to significant deficiencies or material weaknesses) in the Company's internal controls or in other factors that could significantly affect internal controls subsequent to the date of the most recently completed evaluation.

PART IV

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

1. **Financial Statements:**

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

Independent Auditor's Report

Consolidated Balance Sheets as of December 31, 2002 and 2001

Consolidated Statements of Operations for the years ended December 31, 2002, 2001 and 2000

Consolidated Statements of Changes in Stockholders' Equity for the years ended December 31, 2002, 2001 and 2000

Consolidated Statements of Cash Flows for the years ended December 31, 2002, 2001 and 2000

Notes to the Consolidated Financial Statements

2. **Reports on Form 8-K**

None

3. **Exhibits**

Exhibit Number	Title
3.1	— Restated Certificate of Incorporation of Energy Partners, Ltd., dated as of November 16, 1999 (incorporated by reference to Exhibit 3.1 to EPL's registration statement on Form S-1 (File No. 333-42876)).
3.2	— Amendment to Restated Certificate of Incorporation of Energy Partners, Ltd., dated as of September 15, 2000 (incorporated by reference to Exhibit 3.2 to EPL's registration statement on Form S-1 (File No. 333-42876)).
3.3	— Certificate of Elimination of the Series A Convertible Preferred Stock, Series B Convertible Preferred Stock and Series C Preferred Stock of Energy Partners, Ltd. (incorporated by reference to Exhibit 4.2 of EPL's Form 8-K filed January 22, 2002).
3.4	— Certificate of Designation of the Series D Exchangeable Convertible Preferred Stock of Energy Partners, Ltd. (incorporated by reference to Exhibit 4.3 of EPL's Form 8-K filed January 22, 2002).
3.5	— Amended and Restated Bylaws of Energy Partners, Ltd., dated as of 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)).
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)).

Exhibit Number		Title
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 (incorporated by reference to EPL's proxy statement on Form 14A filed March 27, 2002 (File No. 001-16179)).
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. (incorporated by reference to Exhibit 10.4 to EPL's Form 10-K filed March 15, 2002 (File No. 001-16179)).
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 filed February 20, 2001 (File No. 333-55940)).
10.6	—	First Amendment to Stock and Deferral Plan for Non-Employee Directors. (incorporated by reference to Exhibit 10.6 to EPL's Form 10-K filed March 15, 2002 (File No. 001-16179)).
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*	—	Third Amended and Restated Revolving Credit Agreement, among Energy Partners, Ltd., EPL of Louisiana, L.L.C. and Delaware EPL of Texas, LLC, the undersigned banks and financial institutions that are parties to the Credit Agreement and Bank One, N.A., dated as of November 1, 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)).
10.18	—	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)).
10.19	—	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)).

Exhibit Number	Title
10.20	— 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).
10.21	— 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).
10.22	— 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).
10.23	— 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).
10.24	— First Amendment to Earnout Agreement between Energy Partners, Ltd. and Participants effective July 1, 2002 (incorporated by reference to Exhibit 10.1 to EPL's Form 10-Q filed November 13, 2002).
10.25	— Separation Agreement by and between Energy Partners, Ltd. and Maureen O. Sullivan dated as of March 26, 2002. (incorporated by reference to Exhibit 10.1 to EPL's Form 10-Q filed May 14, 2002).
21.1*	— Subsidiaries of Energy Partners, Ltd.
23.1*	— Consent of KPMG LLP.
23.2*	— Consent of Netherland, Sewell & Associates, Inc.
23.3*	— Consent of Ryder Scott Company, L.P.
99.1*	— Report of Independent Petroleum Engineers dated as of January 30, 2003.
99.2*	— Report of Independent Petroleum Engineers dated as of January 31, 2003.

* Filed herewith

SIGNATURES

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

ENERGY PARTNERS, LTD.

By: /s/ RICHARD A. BACHMANN

Richard A. Bachmann
Chairman, President
and Chief Executive Officer

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

Signature	Title	Date
/s/ RICHARD A. BACHMANN Richard A. Bachmann	Chairman, President and Chief Executive Officer (Principal Executive Officer)	March 13, 2003
/s/ SUZANNE V. BAER Suzanne V. Baer	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 13, 2003
/s/ AUSTIN M. BEUTNER Austin M. Beutner	Director	March 12, 2003
/s/ JOHN C. BUMGARNER, JR. John C. Bumgarner, Jr.	Director	March 12, 2003
/s/ HAROLD D. CARTER Harold D. Carter	Director	March 6, 2003
/s/ ROBERT D. GERSHEN Robert D. Gershen	Director	March 12, 2003
/s/ GARY L. HALL Gary L. Hall	Director	March 12, 2003
/s/ WILLIAM O. HILTZ William O. Hiltz	Director	March 12, 2003
/s/ EAMON M. KELLY Eamon M. Kelly	Director	March 13, 2003
/s/ JOHN G. PHILLIPS John G. Phillips	Director	March 12, 2003

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 Executive Officer
Utica Plaza Management Company

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

Robert D. Gershen (2)(3)
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)(3)
President Emeritus and Professor
Tulane University

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

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

OFFICERS

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

Gary L. Hall
Vice Chairman of the Board

Suzanne V. Baer
Executive Vice President and
Chief Financial Officer

Clinton W. Coldren
Executive Vice President and
Chief Operating Officer

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

Bruce R. Sidner
Executive Vice President of Exploration

T. Rodney Dykes
Vice President

L. Keith Vincent
Vice President

Louis E. Willhoit, Jr.
Vice President

Kenneth P. Smith
Treasurer

CORPORATE INFORMATION

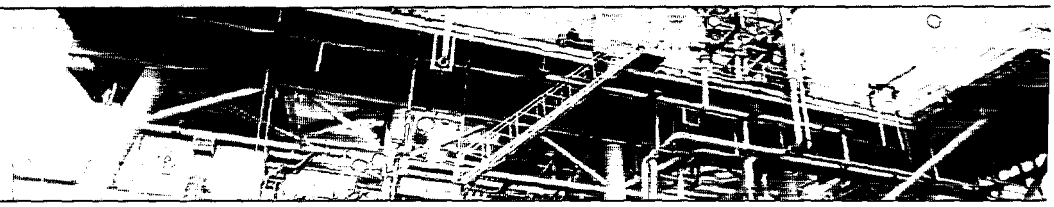
Corporate Office
201 St. Charles Avenue
Suite 3400
New Orleans, LA 70170
504-569-1875

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 Tuesday, May 6, 2003.

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.



ABBREVIATIONS

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

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

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

EPL

ENERGY PARTNERS, LTD.