PE

12-31-04

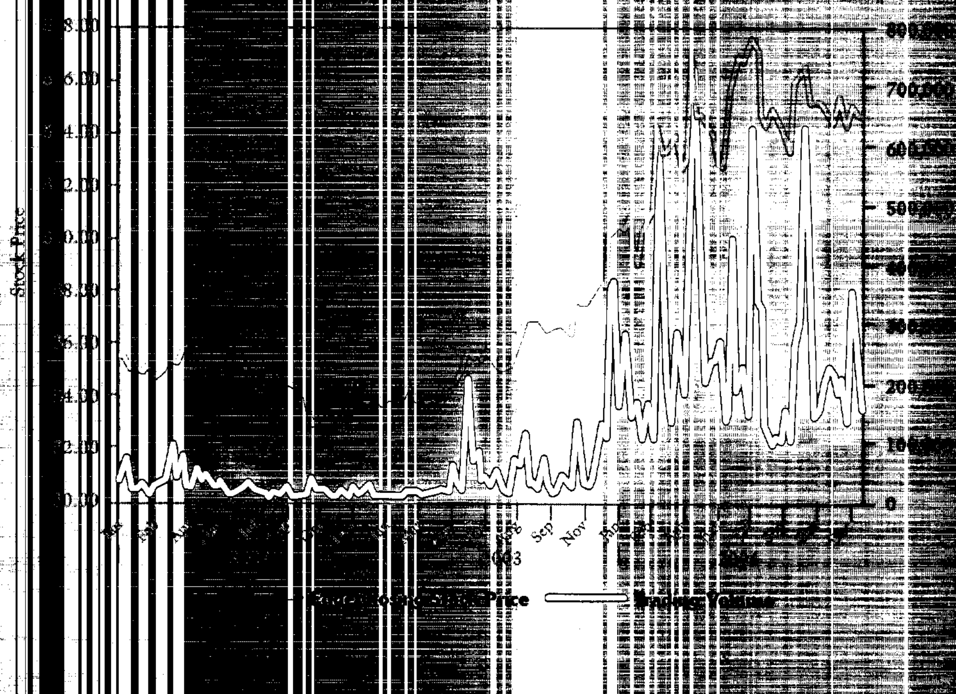
ARLS

Our Growth Reflects Our Strategy

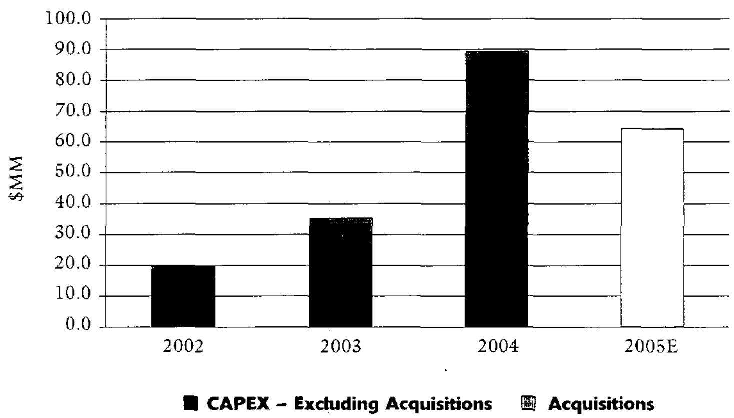
FINANCIAL HIGHLIGHTS

	2004	2003	2002

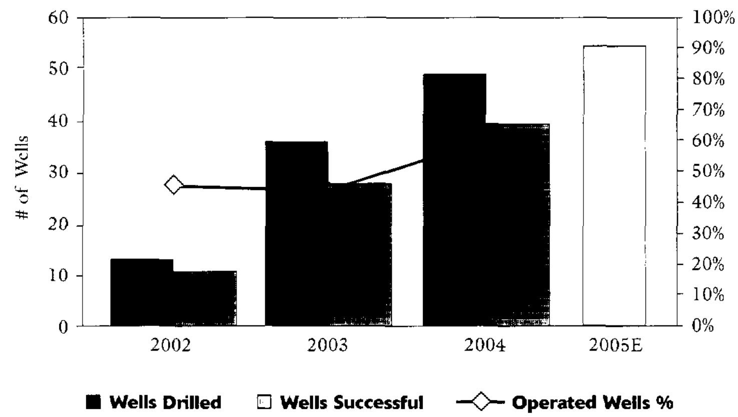
- Natural gas [illegible]
  - 86% of [illegible] at 12/31/04 were natural gas or natural [illegible]
  - 76% of [illegible] production is natural gas
- Balanced [illegible] development property base focused in
  - the o[illegible] South Texas [illegible] Mississippi
  - the P[illegible] Texas and New Mexico
- Track record [illegible]
  - Three [illegible] rate of 81%
  - Three [illegible] growth rate in proved reserves of [illegible]
  - Three [illegible] growth rate in production of 32%
  - Three [illegible] replacement of 263%
- As of Dece[illegible] 4
  - Opera[illegible] production
  - 49.1 [illegible] net daily production
  - 135,6[illegible] developed and option acres
- Value Driv[illegible]
  - Reser[illegible] growth combined with a conservative financ[illegible]



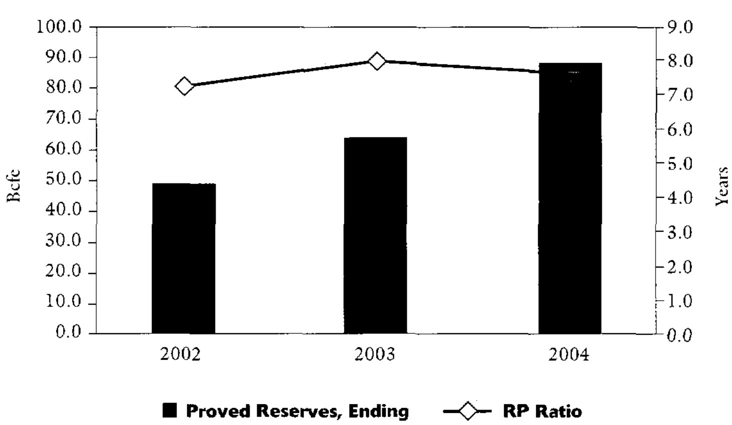
We have elected to change the form of information provided in our previous Annual Reports. Our intent is to provide readers with a graphical and bullet point text that we believe conveys a meaningful summary and perspective of the Company's performance and objectives.



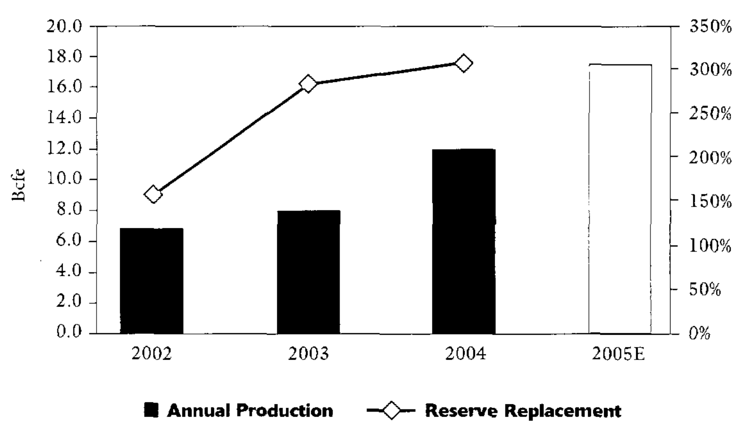
- Drilling capital expenditures have grown steadily, up 170% since 2002.
- Drilling capital expenditures for 2005 are forecast to increase about 30% over 2004.
- Acquisition capital spending has grown steadily. In December 2004 we spent a net $40 million to acquire assets in South Texas.



- Steady increase in the number of wells drilled with drilling success rate of 81% since 2002.
- Increased percentage of wells operated results in better control over costs and timing.
- 2005 wells drilled expected to increase over 2004 with a similar percentage operated.

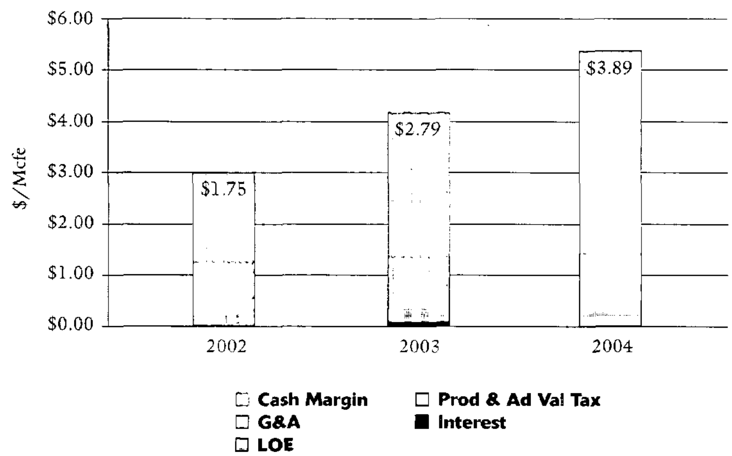


- 35% compounded growth rate in reserves since 2002.
- Natural gas and natural gas liquids comprise 86% of 2004 reserves and 75% of 2004 reserves are developed.
- Our reserve to production ratio has grown from 3.7 years in 1999 to 7.4 years at year-end 2004.



- 32% compounded growth rate in production since 2002.
- Production for 2005 is expected to increase 43% to 47% over 2004.
- 308% production replacement in 2004 and 263% over the 2002–2004 period.

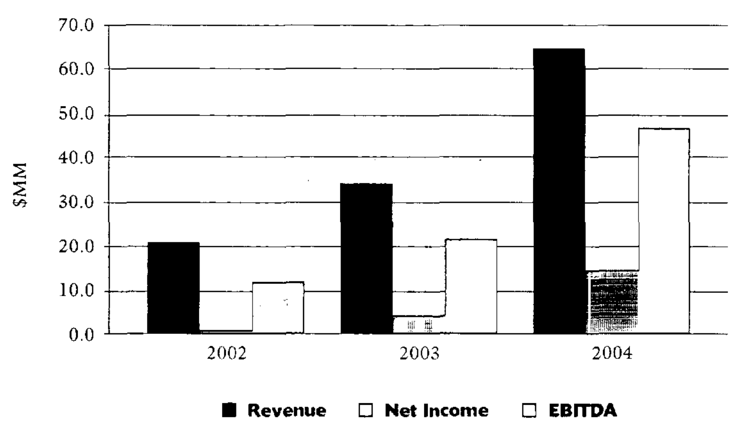
Attention to cost structure and financial flexibility goes hand-in-hand with operational strategies.



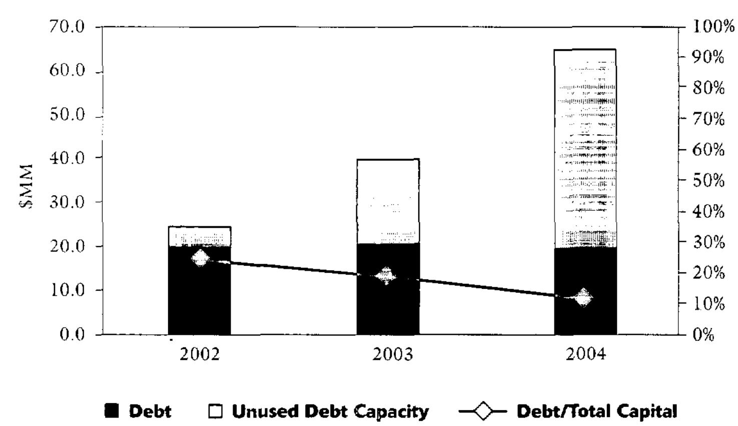
	2002	2003	2004
Per Mcfe Analysis – $ / Mcfe[1]			
Revenue (after effect of hedging)	$3.01	$4.19	$5.33
LOE	0.32	0.33	0.41
Production & Ad Val. Taxes	0.23	0.30	0.36
G&A[2]	0.69	0.68	0.65
Interest & Other[3]	0.02	0.08	0.03
Total Expense	$1.26	$1.40	$1.45
Cash Margin	**$1.75**	**2.79**	**3.89**
Cash Margin Percentage of Revenue	58%	67%	73%
DD&A	1.50	1.68	1.81
Net Margin	$0.25	1.12	2.08
Net Margin Percentage of Revenue	8%	27%	39%
Number of Employees	33	35	51

[1] *Totals may not add due to rounding.*
[2] *Excludes deferred compensation expense.*
[3] *Interest excludes capitalized interest and amortization of deferred loan costs.*

- Our cash margin has grown due to a company-wide focus on cost control complemented by increased commodity prices.
- Our growth in reserves and production has caused us to increase our workforce from 33 in 2002 to 51 in 2004.
- We hedge a portion of our production each year to help insure our margins and ability to conduct our capital program.
- Although we have expanded our workforce, G&A per unit of production has steadily decreased and is forecast to decrease again on a per unit basis in 2005.
- Production taxes move in a direct relationship with commodity prices.



- Increased reserves and production coupled with rising commodity prices and attention to cost have resulted in growing revenue, net income and EBITDA.
- This growth in EBITDA has allowed us to steadily increase our capital program.



- We have been prudent about utilizing our growing debt capacity resulting in unparalleled financial flexibility to execute all elements of our strategy.
- Our drilling capital expenditures are funded from operating cash flow leaving our unused debt capacity for future growth opportunities.

2004 production, revenue, net income, earnings per share and year-end reserves were all the highest in Edge's history and we are positioned to further improve on these results in 2005.

We began 2004 with a record daily producing rate fueled by three successful transactions in the prior year and the results of successful drilling in the second half of 2003. In addition, we expanded our drilling program to 49 wells in 2004, a 36% increase over the 2003 level, while maintaining our historically high success rate. Consequently, our full-year production of 12.1 Bcfe showed a year-over-year gain of 49%.

Our financial flexibility increased through the course of 2004 as a result of strong cash flow, fueled by our increased production and higher commodity prices, increased borrowing capacity and a secondary stock offering of $55 million under our $150 million shelf registration statement. The assets we acquired in 2003 proved to have considerable exploitable potential, as we had envisioned, and our 2005 capital expenditure program will continue to focus on the exploitation of those assets.

At year-end 2004, we closed on a significant acquisition of producing assets in south Texas. The acquisition added 16.4 Bcfe of net proved reserves, which brought our year-end net reserves to 89.1 Bcfe, an increase of 39% over year-end 2003 net reserves of 63.9 Bcfe. We replaced 308% of our record 2004 production of 12.1 Bcfe. In conjunction with the acquisition, we issued 3.5 million new shares of common stock in December, which was used to pay for the post closing adjusted purchase price of $40 million and to modestly reduce our outstanding debt. As a result, we exited 2004 with a debt-to-total capital ratio of 11.7% and $45 million of unused borrowing capacity.

We have never been as strong financially and have never had the kind of flexibility to aggressively execute all aspects of our strategic business plan as we have today. As a result, we believe that our activities will continue to yield profitable growth.

Our stock price, a primary measure of shareholder value, closed at $10.12 on December 31, 2003 and by December 31, 2004 the share price closed at $14.58, an increase of 44%. Our market capitalization increased from $127 million to over $241 million during this same period. By anyone's assessment, these positive increases reflect added shareholder value.

Our planned 2005 capital expenditure program for wells, land, seismic and other related activities will be between $60 to $65 million and we expect to fund this program through internal cash flow. Our plans include the drilling of 50 to 55 wells and the program is designed on a risk adjusted basis to replace our produced reserves as well as achieve at least a 15 to 20 percent growth in our net proven reserves year-over-year, excluding any future acquisitions. About a third of our capital expenditures are for the drilling of proven undeveloped reserves, which we attempt to bring to a producing state within a reasonable time frame – generally 12 months. We will continue to be very active in south Texas where our efforts in the Lobo and Queen City plays have yielded very positive results.

We believe we have turned the corner on our Atoka/Morrow efforts in southeast New Mexico and are very pleased with the well results we are achieving in the shallow Grayburg/San Andres sections. We expect a continued high level of activity in this area.

Our first deep well in the Mississippi Salt Basin was successful and we are planning to drill one or two additional wells in 2005. Efforts to expand our position are underway at this time.

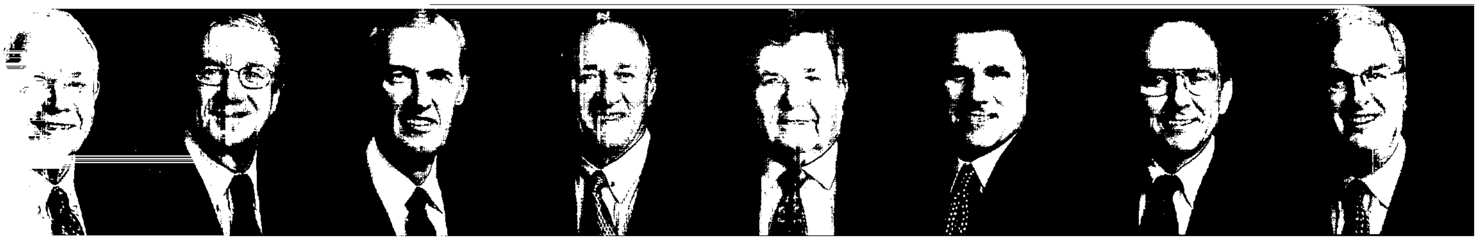
Our 2005 production is projected to increase 43% to 47% over our 2004 level on a risked adjusted basis and this increase does not include the impact of any acquisition we might make during the year.

Our comprehensive Business Plan provides us with a strategic framework that helps us focus our operational and financial efforts on value adding activities. Efforts directed toward expanding the Company's position in its core areas and into new attractive areas requires different approaches – internal prospect generation, farm-ins, partnerships, alliances, trades and acquisitions. As you are probably aware, we have used all of these approaches in the past to enhance the Company's position and will continue to do so because we believe this is the best way for Edge to continue building shareholder value.

Sincerely,

John W. Elias
Chairman, President & CEO

Board of Directors



Officers/Management

Outside Legal Counsel

Independent Registered Public Accounting Firm

Market Information

Annual Meeting

Form 10-K

an integral part of the Annual ...
Stockholders. Additional copies ...

1301 Travis, Suite 2000

Definitions

Mcf

Bcfe

EBITDA

Mcfe

MMcfe

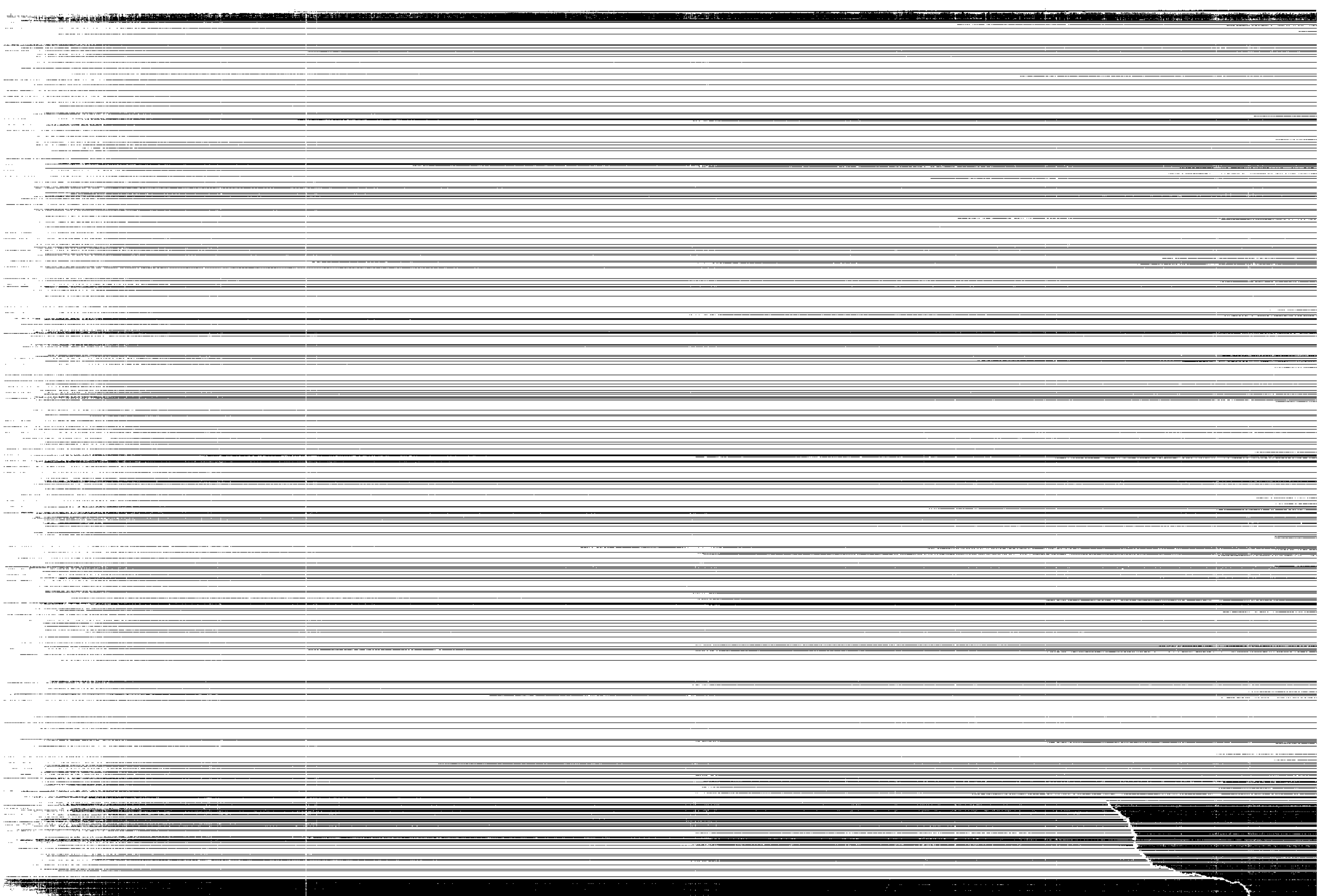
MMcf

LNG

Focus Areas

Corporate Headquarters

Transfer Agent



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

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2004
OR

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

For the transition period from to

Commission file number: 0-22149

EDGE PETROLEUM CORPORATION
(Exact name of Registrant as specified in its charter)

Delaware	76-0511037
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1301 Travis, Suite 2000 Houston, Texas	77002
(Address of principal executive offices)	(Zip code)

713-654-8960
(Registrant's telephone number including area code)

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

None

Securities registered pursuant to Section 12(g) of the Act:
Common Stock, Par Value $.01 Per Share

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 X 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 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. [X]

Indicate by check mark whether the registrant is an accelerated filer.

Yes X No__

As of June 30, 2004, the aggregate market value of the voting stock held by non-affiliates of the registrant was $210.5 million (based on a value of $17.00 per share, the closing price of the Common Stock as quoted by NASDAQ National Market on such date).

As of March 11, 2005, 17,100,155 shares of Common Stock, par value $.01 per share, were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the registrant's 2005 Annual Meeting of Shareholders, to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, are incorporated by reference into Part III of this report.

TABLE OF CONTENTS

EDGE PETROLEUM CORPORATION

Unless otherwise indicated by the context, references herein to the "Company", or "Edge", "we", "our" or "us" mean Edge Petroleum Corporation, a Delaware corporation, and its corporate and partnership subsidiaries and predecessors. Certain terms used herein relating to the oil and natural gas industry are defined in ITEMS 1 AND 2. "BUSINESS AND PROPERTIES – CERTAIN DEFINITIONS."

FORWARD LOOKING INFORMATION

Certain of the statements contained in all parts of this document (including the portion, if any, to which this Form 10-K is attached), including, but not limited to, those relating to our drilling plans (including scheduled and budgeted wells), the effect of changes in strategy and business discipline, future tax matters, our 3-D project portfolio, future general and administrative expenses on a per unit of production basis, changes in wells operated and reserves, future growth and expansion, future exploration, future seismic data (including timing and results), expansion of operation, our ability to generate additional prospects, review of outside generated prospects and acquisitions, additional reserves and reserve increases, replace production and manage our asset base, enhancement of visualization and interpretation strengths, expansion and improvement of capabilities, integration of new technology into operations, credit facilities, redetermination of our borrowing base, attraction of new members to the technical team, future compensation programs, new focus on core areas, new prospects and drilling locations, new alliances, future capital expenditures (or funding thereof) and working capital, sufficiency of future working capital, borrowings and capital resources and liquidity, projected rates of return, retained earnings and dividend policies, projected cash flows from operations, future commodity price environment, expectation or timing of reaching payout, outcome, effects or timing of any legal proceedings or contingencies, the impact of any change in accounting policies on our financial statements, the number, timing or results of any wells, realization of post-closing price adjustments with respect to the Contango Asset Acquisition, the plans for timing, interpretation and results of new or existing seismic surveys or seismic data, future production or reserves, future acquisition of leases, lease options or other land rights, management's assessment of internal control over financial reporting and our independent registered public accounting firm's attestation and report on management's assessment, the identification of material weaknesses in internal control over financial reporting and any other statements regarding future operations, financial results, opportunities, growth, business plans and strategy and other statements that are not historical facts are forward looking statements. These forward-looking statements reflect our current view of future events and financial performance. When used in this document, the words "budgeted," "anticipate," "estimate," "expect," "may," "project," "believe," "intend," "plan," "potential," "forecast," "might," "predict," "should" and similar expressions are intended to be among the statements that identify forward-looking statements. These forward-looking statements speak only as of their dates and should not be unduly relied upon. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events, or otherwise. Such statements involve risks and uncertainties, including, but not limited to, those set forth under *ITEMS 1 AND 2. "BUSINESS AND PROPERTIES* – RISK FACTORS" and other factors detailed in this document and our other filings with the Securities and Exchange Commission. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. All subsequent written and oral forward-looking statements attributable to the Company or to persons acting on its behalf are expressly qualified in their entirety by reference to these risks and uncertainties.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

Overview

Edge Petroleum Corporation is an independent oil and natural gas company engaged in the exploration, development, acquisition and production of crude oil and natural gas properties in the United States. Edge was founded in 1983 as a private company and went public in 1997 through an initial public offering. We have evolved over time from a prospect generation organization focused on high-risk, high-reward exploration projects to a team-driven organization focused on a balanced program of exploration, exploitation, development and acquisition of oil and natural gas properties. Following a top-level management change in late 1998, a more disciplined style of business planning and management was integrated into our technology-driven drilling activities. We believe the continuation of this disciplined business model will result in continued growth in reserves, production and financial strength.

Recent Developments

At year-end 2004, our net proved reserves were 89.1 Bcfe, comprised of 66.3 billion cubic feet of natural gas, 1.8 million barrels of natural gas liquids and 2.0 million barrels of crude oil and condensate. Natural gas and natural gas liquids accounted for approximately 86% of those proved reserves. Approximately 75% of total proved reserves were developed as of year-end 2004 and they were all located onshore, in the United States. We spent much of 2004 (i) developing and exploiting assets acquired late in 2003, including those assets involved in our southeast New Mexico exploration alliance entered into late in 2003, and (ii) developing our remaining core asset base. Late in 2004, we completed a public offering of 3.5 million shares of our common stock and acquired interests in certain south Texas oil and gas properties from Contango Oil & Gas Company ("Contango"). On February 14, 2005, we announced that we had entered into a new exploration and development venture to jointly explore for oil and natural gas in south Texas with a private oil and gas company. This venture will be called the "Vista Nueva" project and it will give the Company access to 3-D seismic data covering a portion of its recently acquired assets plus undeveloped acreage and an exclusive option to secure leases of unleased minerals in the project area.

Strategy

Our business strategy is based on the following six main elements:

Grow reserves through the drilling of a balanced portfolio of prospects

We seek to maintain a prudent balance between higher risk/reward wells and more moderate risk/reward wells. In 2004, we drilled 49 wells (26.91 net), primarily in Texas, with 40 of those wells completed as productive for an apparent success rate of approximately 82%. This drilling program, along with our acquisition of certain oil and gas assets from Contango, helped us to grow our year-end reserves by 39% and replaced 308% of our production (see *ITEMS I AND 2. BUSINESS AND PROPERTIES* – "Oil and Natural Gas Reserve Replacement"). Our drilling program for 2005 is focused primarily in south Texas, and to a lesser extent in southeastern New Mexico. We expect to drill between 50 and 55 wells (28 and 31 net, respectively) in 2005 and we estimate capital spending for drilling for the year to be approximately $50 million. In addition, we have a contingent drilling program that could add up to $20 million to $25 million to this estimate. Our contingent drilling program is dependent upon certain factors, including success of various related wells, commodity pricing, obtaining certain leases and the availability of sufficient cash flow from operations to execute the program without materially increasing our debt.

Balance exploration risk with the exploitation of existing properties and acquisitions that we believe have upside potential

In 2004, 56% of our reserve growth came from our drilling activity (which includes additions, extensions and revisions from new drilling, well work and the addition of certain proved undeveloped locations) and the remaining 44% came from acquisitions. We seek acquisitions of producing properties that typically have exploration or exploitation upside potential. We primarily seek properties in our existing core areas, or as a means to establish new core areas. We spent considerable effort in 2004 on acquisitions and in December 2004 we successfully closed the Contango Asset Acquisition, the largest acquisition in our history. We continue to work diligently to identify and evaluate acquisition opportunities with the goal of identifying those that we believe would fit our strategic plan and add shareholder value.

We believe our core drilling program has the potential to replace our production and to provide moderate reserve growth while our higher-risk drilling program and acquisitions have the potential to rapidly accelerate our growth as well as add to future drilling opportunities.

Focus on specific geographic areas where we believe we can add value

We believe geographic focus is a critical element of success. Long-term success requires detailed knowledge of both geologic and geophysical attributes, as well as operating conditions in our chosen areas. As a result, we focus on a select number of geographic areas where our experience and strengths can be applied with a significant influence on the outcome. We believe this focus will allow us to manage a growing asset base and add value to additional properties while controlling incremental costs and staffing requirements.

Integrate technological advances into our exploration, drilling, production operations and administration

We use advanced technologies as risk reduction tools in our exploration, development, drilling and completion activities. Data analysis techniques and advanced processing techniques combined with our more traditional sub-surface interpretation techniques allow our team of technical personnel to more easily identify features, structural details and fluid contacts, that could be overlooked using less sophisticated data interpretation techniques. As of December 31, 2004, we had rights to approximately 2,470 square miles of 3-D seismic data principally located in Texas, Louisiana and Mississippi.

Maintain a conservative financial structure and control our cost structure

We believe that a conservative financial structure is crucial to consistent, positive financial results, management of cyclical swings in our industry and the ability to move quickly to take advantage of acquisitions and attractive drilling opportunities. In order to maximize our financial flexibility, we try to maintain a total debt-to-capital ratio of less than 30%. At December 31, 2004, our debt-to-total capital ratio was 11.7%.

We try to fund most of our ongoing capital expenditures from cash flow from operations, reserving our debt capacity for potential investment opportunities that we believe can profitably add to our program. Part of a sound financial structure is constant attention to costs, both operating and overhead costs. Over the past several years, we have worked diligently to control our operating costs and overhead costs and instituted a formal, disciplined capital budgeting process. We strive to be creative with the use of partnerships and alliances so as to leverage capital resources and enhance our ability to meet our objectives.

Use equity ownership and performance based compensation programs to attract and retain a high-quality workforce

Following a management change in late 1998, we eliminated the previous overriding royalty compensation system and replaced it with a system designed to reward all employees through performance-based compensation that is competitive with our peers and through equity ownership. As of March 11, 2005, our directors and executive officers owned or had options to acquire an aggregate of approximately 11% of our outstanding common stock.

Employees

At the time of this filing, we had 53 full-time employees. We believe that our relationships with our employees are good. None of our employees are covered by a collective bargaining agreement. From time to time, we utilize the services of independent consultants and contractors to perform various professional services, particularly in the areas of construction, design, well site surveillance, permitting and environmental assessment. Field and on-site production operation services, such as pumping, maintenance, dispatching, inspection and testing are generally provided by independent contractors.

Offices

Our principal executive and corporate offices are located in an office building located in Houston, Texas. We lease the space and during the second quarter of 2004 we negotiated a new expanded lease to accommodate our growing Company.

Oil and Natural Gas Reserves

The following table sets forth our estimated net proved oil and natural gas reserves and the present value of estimated future pretax net cash flows related to such reserves as of December 31, 2004. We engaged Ryder Scott Company ("Ryder Scott") and W. D. Von Gonten & Co. ("WDVG") to estimate our net proved reserves, projected future production, estimated future net revenue attributable to our proved reserves, and the present value of such estimated future net revenue as of December 31, 2004. Ryder Scott and WDVG's estimates were based upon a review of production histories and other geologic, economic, ownership and engineering data provided by us. Ryder Scott has independently evaluated our reserves for the past eleven years and WDVG has independently reviewed the reserves we acquired from Contango for the past three years. In estimating the reserve quantities that are economically recoverable, Ryder Scott and WDVG used year-end oil and natural gas prices in effect at December 31, 2004 and estimated development and production costs that were in effect during December 2004 without giving effect to hedging activities. In accordance with requirements of the Securities and Exchange Commission (the "SEC") regulations, no price or cost escalation or reduction was considered by Ryder Scott and WDVG. For further information concerning Ryder Scott and WDVG's estimates of our proved reserves at December 31, 2004, see the reserve reports included as exhibits to this Annual Report on Form 10-K (the "Ryder Scott Report" and the "WDVG Report"). The present value of estimated future net revenues before income taxes was prepared using constant prices as of the calculation date, discounted at 10% per annum on a pretax basis, and is not intended to represent the current market value of the estimated oil and natural gas reserves owned by us. For further information concerning the present value of future net revenue from these proved reserves, see Note 20 to our consolidated financial statements. See *ITEMS 1 AND 2. "BUSINESS AND PROPERTIES* – RISK FACTORS." The oil and natural gas reserve data included in or incorporated by reference in this document are only estimates and may prove to be inaccurate.

	Proved Reserves		
	Developed (1)	**Undeveloped (2)**	**Total**
Oil and condensate (MBbls)(3)	2,698	1,094	3,792
Natural gas (MMcf)	50,698	15,613	66,311
Total Mmcfe	66,886	22,177	89,063
Estimated future net revenue before income taxes	$ 290,766,221	$ 83,221,295	$ 373,987,516
Present value of estimated future net revenue before income taxes (discounted 10% annum) (4)	$ 198,322,069	$ 55,568,791	$ 253,890,860

(1) Proved developed reserves are proved reserves that are expected to be recovered from existing wells with existing equipment and operating methods.

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

(3) Includes natural gas liquids.

(4) Estimated future net revenue represents estimated future gross revenue to be generated from the production of proved reserves, net of estimated future production and development costs, using year-end NYMEX oil and natural gas prices in effect at December 31, 2004, which were $6.18 per MMbtu of natural gas and $43.46 per Bbl of oil.

The reserve data set forth herein represents estimates only. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates made by different engineers often vary from one another. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimates, and such revisions may be material. Accordingly, reserve estimates are generally different from the quantities of oil and natural gas that are ultimately recovered. Furthermore, the estimated future net revenue from proved reserves and the present value thereof are based upon certain assumptions, including current prices, production levels and costs that may not be what is actually incurred or realized.

No estimates of proved reserves comparable to those included herein have been included in reports to any federal agency other than the SEC.

In accordance with SEC regulations, the Ryder Scott Report and the WDVG Report each used year-end oil and natural gas prices in effect at December 31, 2004. The prices used in calculating the estimated future net revenue attributable to proved reserves do not necessarily reflect market prices for oil and natural gas production subsequent to December 31, 2004. There can be no assurance that all of the proved reserves will be produced and sold within the periods indicated, that the assumed prices will actually be realized for such production or that existing contracts will be honored or judicially enforced.

Oil and Natural Gas Reserve Replacement

Finding and developing sufficient amounts of natural gas and crude oil reserves at economical costs are critical to the Company's long-term success. Our business, as with other extractive industries, is a depleting one in which each gas equivalent unit produced must be replaced or we, and a critical source of our future liquidity, will shrink. Given the inherent decline of reserves resulting from the production of those reserves, it is important for an exploration and production company to demonstrate a long-term trend of more than offsetting produced volumes with new reserves that will provide for future production. Management uses the reserve replacement ratio, as defined below, as an indicator of the Company's ability to replenish annual production volumes and grow its reserves, thereby providing some information on the sources of future production. Management believes that reserve replacement is relevant and useful information that is commonly used by analysts, investors and other interested parties in the oil and gas industry as a means of evaluating the operational performance and to a greater extent the prospects of entities engaged in the production and sale of depleting natural resources. These measures are often used as a metric to evaluate an entity's historical track record of replacing the reserves that it produced. The reserve replacement ratio is calculated by dividing the sum of reserve additions from all sources (revisions, purchases, extensions and discoveries) by the actual production for the corresponding period. Additions to our reserves are proven developed and proven undeveloped reserves. We expect to continue adding to our reserve base through these activities, but certain factors outside our control may impede our ability to do so (see Risk Factors below). The values for these reserve additions and production are derived directly from the proved reserves table in note 20 to our consolidated financial statements. Accordingly, the Company does not use unproved reserve quantities. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. As an annual measure, the ratio is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not consider the cost or timing of future production of new reserves, it cannot be used as a measure of value creation. The ratio does not distinguish between changes in reserve quantities that are developed and those that will require additional time and funding to develop. In that regard, it might be noted that the percentage of reserves that were developed was 75%, 78% and 68% for the years ended December 31, 2004, 2003 and 2002, respectively. Set forth below is our reserve replacement ratio for the years ended December 31, 2004, 2003 and 2002.

	For the year ended December 31,			
	2004	2003	2002	Three Year Average
Reserve Replacement Ratio	308%	285%	161%	263%

Oil and Natural Gas Volumes, Prices and Operating Expense

The following table sets forth certain information regarding production volumes, average sales prices and average operating expense associated with our sale of oil and natural gas for the periods indicated.

	Year Ended December 31,		
	2004	**2003**	**2002**
Production:			
Oil and condensate (MBbls)	215	123	120
Natural gas liquids (MBbls)	276	178	161
Natural gas (MMcf)	9,148	6,290	5,266
Natural gas equivalent (MMcfe)	12,093	8,093	6,951
Average Sales Price - before hedging and derivatives:			
Oil and condensate ($ per Bbl)	$ 39.77	$ 31.48	$ 22.88
Natural gas liquids ($ per Bbl)	$ 15.83	$ 12.37	$ 10.31
Natural gas ($ per Mcf)	$ 5.91	$ 5.14	$ 3.20
Natural gas equivalent ($ per Mcfe)	$ 5.54	$ 4.74	$ 3.06
Average Sales Price - after hedging and derivatives:			
Oil and condensate ($ per Bbl)	$ 33.03	$ 31.48	$ 22.88
Natural gas liquids ($ per Bbl)	$ 15.83	$ 12.37	$ 10.31
Natural gas ($ per Mcf)	$ 5.80	$ 4.43	$ 3.14
Natural gas equivalent ($ per Mcfe)	$ 5.33	$ 4.19	$ 3.01
Average oil and natural gas operating expenses including production and ad valorem taxes ($ per Mcfe)(1)	$ 0.77	$ 0.63	$ 0.55

(1) Includes direct lifting costs (labor, repairs and maintenance, materials and supplies), expensed workover costs and the administrative costs of field production personnel, insurance and production and ad valorem taxes.

Exploration, Development and Acquisition Capital Expenditures

The following table sets forth certain information regarding the total costs incurred associated with exploration, development and acquisition activities.

	Year Ended December 31, 2004	2003	2002
		(in thousands)	
Acquisition costs:			
Unproved properties	$ 12,163	$ 6,052	$ 5,466
Proved properties	33,980	10,374	1,369
Exploration costs	8,297	6,017	4,725
Development costs	34,548	12,271	7,927
Subtotal	88,988	34,714	19,487
Asset retirement costs (1)	278	898	--
Total costs incurred	$ 89,266	$ 35,612	$ 19,487

(1) Excluded from asset retirement costs in 2003 was $640,400 related to the cumulative effect of the adoption of SFAS No. 143 on January 1, 2003. See Note 7 to our consolidated financial statements.

Net costs incurred excludes sales of proved oil and natural gas properties which are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves.

Drilling Activity

The following table sets forth our drilling activity for the three years ended December 31, 2004. In the table, "Gross" refers to the total wells in which we have a working interest or back-in working interest after payout and "Net" refers to gross wells multiplied by our working interest therein.

	For the Year Ended December 31, 2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Exploratory:						
Productive	5	2.35	10	7.05	4	3.45
Non-productive	5	2.50	8	4.25	--	--
Total	10	4.85	18	11.30	4	3.45
Development:						
Productive	35	19.33	18	6.62	7	2.69
Non-productive	4	2.73	--	--	2	0.54
Total	39	22.06	18	6.62	9	3.23
Grand Total	49	26.91	36	17.92	13	6.68

Productive Wells

The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2004.

	Company-Operated		Non-Operated		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil	14	8.56	54	16.93	68	25.49
Natural gas	89	71.37	160	51.37	249	122.74
Total	103	79.93	214	68.30	317	148.23

Acreage Data

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of December 31, 2004. Developed acres refer to acreage within producing units and undeveloped acres refer to acreage that has not been placed in producing units.

	Developed Acres		Undeveloped Acres		Total	
	Gross	Net	Gross	Net	Gross	Net
Montana	--	--	17,715	11,658	17,715	11,658
Michigan	160	160	498	498	658	658
Alabama	536	3	40	1	576	4
Louisiana	3,307	726	3,423	435	6,730	1,161
New Mexico	3,448	1,337	94,310	18,135	97,758	19,472
Mississippi	8,962	3,193	2,989	1,233	11,951	4,426
Texas	59,588	25,905	15,176	4,291	74,764	30,196
Total	76,001	31,324	134,151	36,251	210,152	67,575

Leases covering approximately 4,679 gross (2,695 net), 6,715 gross (1,964 net) and 12,769 gross (8,722 net) undeveloped acres are scheduled to expire in 2005, 2006 and 2007, respectively. In general, our leases will continue past their primary terms if oil and natural gas production in commercial quantities is being produced from a well on such lease.

The table does not include (i) 80,000 gross (68,000 net) acres that we have a right to acquire on or before July 26, 2005 pursuant to an Indian Mineral Development Agreement with the Blackfeet Indian Tribe or (ii) 1,300 gross (325 net) acres in Louisiana that we have the right to acquire on or before October 20, 2005.

Core Areas of Operation

As of December 31, 2004, 77.1% of our proved reserves were in south Texas, 10.7% in south Louisiana and 12.2% in New Mexico, Michigan, Mississippi and Alabama. During 2004, we added reserves and production in our new core area in southeastern New Mexico, as a result of an exploration and development alliance entered into in late 2003 and as a result of the Contango Asset Acquisition.

The table below sets forth the gross and net number of our gas and oil wells in each of our core areas of operation as of December 31, 2004.

	Gas Wells		Oil Wells	
	Gross	Net	Gross	Net
Texas	222	111.95	40	18.23
Louisiana	7	1.40	--	--
Mississippi	13	5.47	18	3.73
Alabama	1	--	4	0.22
Michigan	1	1.00	--	--
New Mexico	4	2.42	7	3.81
Total	248	122.24	69	25.99

Texas

We currently own an interest in 74,764 gross (30,196 net) acres in south and south-central Texas. Our areas of focus in this region are predominantly in the Wilcox (Lobo), Queen City, Yegua, Vicksburg and Frio producing trends. As of December 31, 2004, we operated approximately 88 producing wells, accounting for about 77% of our total net production in Texas. We drilled 32 wells during 2004 in Texas, 26 of which were successfully completed. The majority of our 2004 drilling activity took place at the Gato Creek (Lobo), and Encinitas (Vicksburg) Project Areas. We drilled eight successful wells at Gato Creek and installed additional compression to improve production performance. Twelve successful wells were drilled in the Encinitas Field in 2004. In 2005, we currently expect to drill 30 to 35 wells (20.5 to 25.5 net, respectively) in our core areas in Texas. The majority of these wells are planned in the Gato Creek area, the Encinitas Field, and in a new Queen City project area in Jim Hogg County.

We made one cash asset acquisition in Texas during 2004. The acquisition added to our existing position, notably in the Queen City trend in Jim Hogg County, Texas (see Note 6 to our consolidated financial statements).

Louisiana

We currently own an interest in 6,730 gross (1,161 net) acres in south Louisiana. Our operations in this area have been focused in the prolific gas-producing region covering portions of Acadia, Calcasieu, Lafayette, St. Landry and Vermilion Parishes. As of December 31, 2004, we had an interest in seven wells, none of which we operate. One exploratory well was drilled in Calcasieu Parish in late 2004, and was a dry hole. We currently have plans to participate with a 25% working interest in up to two 13,000-foot exploratory tests in 2005. These wells will be located in Calcasieu Parish in southwest Louisiana and will target the Frio age Hackberry sands. We also plan to drill a development well offsetting the Thibodeaux #1 ST well located in Lafayette Parish.

Mississippi

We currently own an interest in 11,951 gross (4,426 net) acres in Mississippi. We acquired additional reserves and production in the Mississippi Salt Basin in south central Mississippi as part of the 2003 merger with Miller Exploration Company ("Miller"). The primary producing horizons in the Mississippi Salt Basin around the Miller properties include the Hosston, Sligo, Rodessa and James Lime sections. As of December 31, 2004, we operated nine producing wells, accounting for about 83% of our total net production in Mississippi. In 2004 we completed a Lower Hosston well at Centerville Dome, and acquired 3-D seismic over Midway Dome. In 2005, we plan to acquire additional 3-D seismic and could drill one to two wells (0.9 to 1.1 net) in this area.

Michigan

We currently own an interest in 658 gross (658 net) acres in Michigan. We acquired acreage and one producing well in south central Michigan as part of the 2003 merger with Miller. This well is operated by Edge and produces from the Trenton/Black River formation at approximately 3,000 feet. We have no plans for additional activity in Michigan in 2005 at this time.

New Mexico / West Texas – Permian Basin

We established a new core area in southeastern New Mexico through an alliance with two private companies in 2003. We currently own an interest in 97,758 gross (19,472 net) acres in this area that we earned through a drilling obligation that we fulfilled in 2004. The objectives in this area are shallow oil in the Yeso, San Andres, Queen and Grayburg formations, and deep gas in the Atoka and Morrow formations. Additional objectives are the Strawn, Cisco, Wolfcamp and Devonian formations. In 2004, we participated in the drilling of seven (3.7 net) shallow and eight (3.9 net) deep wells. All of the shallow wells and six of the deep wells were completed successfully. We also acquired an additional 2,381 gross (1,557 net) acres from Federal and State lease sales. During 2005, we anticipate drilling approximately 13 (3.8 net) wells in New Mexico, and also anticipate adding to our acreage position in this area through lease sale acquisitions.

Northern Rocky Mountains

We currently own an interest in 4,905 gross (1,352 net) undeveloped acres in the northern Powder River Basin of Montana and also own an interest in 12,810 gross (10,306 net) undeveloped acres as well as an option on 80,000 gross (68,000 net) acres in north central Montana on a portion of the Blackfeet Indian Reservation. Our option on the Blackfeet Indian Reservation was acquired as part of the 2003 merger with Miller. In the event that we do not pay the annual rental of $100,000 by July 26, 2005, our option on the Blackfeet Indian Reservation will terminate. We have no current plans for drilling in the Powder River Basin or on the Blackfeet Indian Reservation.

Title to Properties

We believe we have satisfactory title to all of our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect the value of such properties. As is customary in the industry in the case of undeveloped properties, little investigation of record title is made at the time of acquisition (other than a preliminary review of local records). Detailed investigations, including a title opinion rendered by a licensed attorney, are made before commencement of drilling operations.

We have granted mortgage liens on substantially all of our oil and natural gas properties in favor of Union Bank of California, as agent, to secure our credit facility. These mortgages and the credit facility contain substantial restrictions and operating covenants that are customarily found in loan agreements of this type. See *ITEM 7. "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS* – LIQUIDITY AND CAPITAL RESOURCES – *CREDIT FACILITY"* and Note 10 to our consolidated financial statements.

Marketing

Our production is marketed to third parties consistent with industry practices. We market our own production where feasible, but on occasion engage a third-party marketing agent. Typically, oil is sold at the well-head at field-posted prices and natural gas is sold under contract at a negotiated monthly price based upon factors normally considered in the industry, such as conditioning or treating to make gas marketable, distance from the well to the transportation pipeline, well pressure, estimated reserves, quality of natural gas and prevailing supply/demand conditions.

Our marketing objective is to receive the highest possible wellhead price for our product. We are aided by the presence of multiple outlets near our production on the Gulf Coast. We take an active role in determining the available pipeline alternatives for each property based upon historical pricing, capacity, pressure, market relationships, seasonal variances and long-term viability.

There are a variety of factors which affect the market for oil and natural gas, including the extent of domestic production and imports of oil and natural gas, the proximity and capacity of natural gas pipelines and other transportation facilities, demand for oil and natural gas, the marketing of competitive fuels and the effects of state and federal regulations on oil and natural gas production and sales. We have not experienced any significant difficulties in marketing our oil and natural gas. The oil and natural gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual customers.

Where feasible, we use a combination of market-sensitive pricing and forward-fixed pricing. Forward pricing is utilized to take advantage of anomalies in the futures market and to hedge a portion of our production at prices exceeding forecast. All such hedging transactions provide for financial rather than physical settlement. See *ITEM 7. "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS* – CRITICAL ACCOUNTING POLICIES AND ESTIMATES – DERIVATIVES AND HEDGING ACTIVITIES."

Due to the instability of oil and natural gas prices, we may enter into, from time to time, price risk management transactions (e.g., swaps, collars and floors) for a portion of our oil and natural gas production to achieve a more predictable cash flow, as well as to reduce exposure from price fluctuations. While the use of these arrangements limits our ability to benefit from increases in the price of oil and natural gas, it also reduces our potential exposure to adverse price movements. Our price risk management arrangements, to the extent we enter into any, apply to only a portion of our production, provide only partial price protection against declines in oil and natural gas prices and limit our potential gains from future increases in prices. On a quarterly basis, our management sets all of our price risk management transaction policies, including volumes, accounting treatment, types of instruments and counter parties. These policies are implemented by management through the execution of trades by the Chief Financial Officer after consultation with and concurrence by the President and Chairman of the Board. Our Board of Directors reviews our price risk management policies and trades. We account for these transactions as hedging and derivative activities and, accordingly, certain gains and losses are included in revenue during the period the transactions occur (see Note 9 to our consolidated financial statements).

Although we take some measures to attempt to control price risk, we remain subject to price fluctuations for natural gas sold in the spot market due primarily to seasonality of demand and other factors beyond our control. Domestic oil prices generally follow worldwide oil prices, which are subject to price fluctuations resulting from changes in world supply and demand. We continue to evaluate the potential for reducing these risks by entering into hedge transactions. Included within total revenue for the years ended December 31, 2004, 2003, and 2002 was approximately $2.5 million, $4.5 million and $0.3 million, respectively, representing net losses from hedging and derivative activity as shown in the table below.

	Year Ended December 31,		
	2004	2003	2002
Natural gas hedging contract settlements	$ (328,500)	$ (4,455,590)	$ (326,950)
Crude oil derivative contract settlements	(880,765)	--	--
Hedge premium reclassification	(686,250)	--	--
Oil derivative contract unrealized change in fair value	(564,548)	--	--
Loss on hedging and derivatives	$ (2,460,063)	$ (4,455,590)	$ (326,950)

The table below summarizes the Company's outstanding hedge and derivative contracts reflected on the balance sheet at December 31, 2004 and 2003.

Transaction Date	Transaction Type		Beginning	Ending	Price Per Unit	Volumes Per Day	Fair Value of Outstanding Hedging and Derivative Contracts as of December 31, 2004 (5)	Fair Value of Outstanding Hedging and Derivative Contracts as of December 31, 2003
Natural Gas (1):								
12/03	Natural Gas Collar		01/01/2004	03/31/2004	$4.50-$7.05	5,000MMbtu	$ --	$ 37,688
08/03	Natural Gas Collar	(2)	01/01/2004	03/31/2004	$4.50-$7.00	10,000MMbtu	--	(91,504)
08/03	Natural Gas Collar	(2)	04/01/2004	09/30/2004	$4.50-$6.00	10,000MMbtu	--	42,996
08/03	Natural Gas Collar	(2)	10/01/2004	12/31/2004	$4.50-$7.00	10,000MMbtu	--	131,621
05/04	Natural Gas Collar		01/01/2005	03/31/2005	$5.00-$10.39	10,000MMbtu	92,703	--
07/04	Natural Gas Collar		04/01/2005	06/30/2005	$5.00-$7.53	10,000MMbtu	9,162	--
07/04	Natural Gas Collar		07/01/2005	09/30/2005	$5.00-$7.67	10,000MMbtu	(41,210)	--
10/04	Natural Gas Collar		01/01/2005	12/31/2005	$6.00-$9.52	10,000MMbtu	1,860,375	--
Crude Oil (3):								
03/04	Crude Oil Collar		04/01/2004	12/31/2004	$30.00-$35.50	400Bbl	(96,240)	--
05/04 (08/04)	Crude Oil Collar	(4)	01/01/2005	12/31/2005	$35.00-$40.00	200/290Bbl	(468,308)	--
							$ 1,356,482	$ 120,801

(1) The Company's current hedging activities for natural gas were entered into on a per MMbtu delivered price basis, using the Houston Ship Channel Index, with settlement for each calendar month occurring five business days following the expiration date.

(2) This contract was entered into at a cost of $686,250.

(3) Hedge accounting is not applied to the Company's collars on crude oil, which were entered into on a per barrel delivered price basis, using the West Texas Intermediate Index, with settlement for each calendar month occurring five business days following the expiration date. The change in fair value is reflected in total revenue for the year ended December 31, 2004.

(4) In August 2004, the Company replaced the contract that was entered into May 2004 with a new contract that changes the volume and pricing terms. The put option is on 200 Bbl/D and the call option is on 290 Bbl/D. This transaction was completed at no additional cost to the Company.

(5) The fair value of the Company's outstanding transactions is presented on the balance sheet by counterparty. Our counterparties net our positions with them, but we cannot present the net of the two counterparty positions because we do not have legal right of offset. Therefore one counterparty is presented in the Derivative Asset and one is presented in the Derivative Liability. The crude oil collar with a balance of ($468,308) is presented as a liability and the remaining contracts are presented as an asset. All contracts are considered current.

Sales to Major Customers

We sold natural gas and crude oil production representing 10% or more of our total revenues for the years ended December 31, 2004, 2003, and 2002 as listed below.

	For the year ended December 31,		
Major Purchaser	**2004**	**2003**	**2002**
Upstream Energy Services (1)	22%	38%	24%
ChevronTexaco	22%	6%	18%
Copano Field Services	19%	16%	17%
BTA	2%	18%	5%
Southwestern Energy	1%	5%	15%

NOTE: Amounts disclosed are approximations and those that are less than 10% are presented for information and comparison purposes only. Also these percentages do not consider the effects of financial hedges.

(1) Upstream is an agent that sells our production to other purchasers on our behalf.

In the exploration, development and production business, production is normally sold to relatively few customers. Substantially all of the Company's customers are concentrated in the oil and gas industry, and revenue can be materially affected by current economic conditions and the price of certain commodities such as natural gas and crude oil, the cost of which is passed through to the customer. However, based on the current demand for natural gas and crude oil and the fact that alternate purchasers are readily available, we believe that the loss of any of our major purchasers would not have a long-term material adverse effect on our operations.

Competition

We encounter competition from other oil and natural gas companies in all areas of our operations, including the acquisition of exploratory prospects and proven properties. Our ability to explore for oil and natural gas reserves and to acquire additional properties in the future will be dependent upon our ability to conduct our operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. We believe that our technological expertise, our exploration, land, drilling and production capabilities and the experience of our management generally enable us to compete effectively. (See ITEMS 1 AND 2. "BUSINESS AND PROPERTIES – RISK FACTORS – We face strong competition from larger oil and natural gas companies.")

INDUSTRY REGULATIONS

The availability of a ready market for oil and natural gas production depends upon numerous factors beyond our control. These factors include regulation of oil and natural gas production, federal and state regulations governing environmental quality and pollution control, state limits on allowable rates of production by well or proration unit, the amount of oil and natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive natural gas well may be "shut-in" because of an oversupply of natural gas or lack of an available natural gas pipeline in the areas in which we may conduct operations. State and federal regulations generally are intended to prevent waste of oil and natural gas, protect rights to produce oil and natural gas between owners in a common reservoir, control the amount of oil and natural gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted. The following discussion summarizes the regulation of the United States oil and natural gas industry. We believe that we are in substantial compliance with the various statutes, rules, regulations and governmental orders to which our operations may be subject, although there can be no assurance that this is or will remain the case. Moreover, such statutes, rules, regulations and government orders may be changed or reinterpreted from time to time in response to economic or political conditions, and there can be no assurance that such changes or reinterpretations will not materially adversely affect our results of operations and financial condition. The following discussion is not intended to constitute a complete discussion of the various statutes, rules, regulations and governmental orders to which our operations may be subject.

Regulation of Oil and Natural Gas Exploration and Production. Our operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used in connection with operations. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the density of wells that may be drilled in and the unitization or pooling of oil and natural gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units, and therefore more difficult to develop a project, if the operator owns less than 100 percent of the leasehold. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations may limit the amount of oil and natural gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. The regulatory burden on the oil and natural gas industry increases our costs of doing business and, consequently, affects our profitability. Inasmuch such laws and regulations are frequently expanded, amended and interpreted, we are unable to predict the future cost or impact of complying with such regulations.

Regulation of Sales and Transportation of Natural Gas. Federal legislation and regulatory controls have historically affected the price of natural gas produced by us, and the manner in which such production is transported and marketed. Under the Natural Gas Act ("NGA") of 1938, the Federal Energy Regulatory Commission (the "FERC") regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act (the "Decontrol Act") deregulated natural gas prices for all "first sales" of natural gas, including all sales by us of our own production. As a result, all of our domestically produced natural gas may now be sold at market prices, subject to the terms of any private contracts that may be in effect. However, the Decontrol Act did not affect the FERC's jurisdiction over natural gas transportation.

Our natural gas sales are affected by intrastate and interstate gas transportation regulation. Following the Congressional passage of the NGPA, the FERC adopted a series of regulatory changes that have significantly altered the transportation and marketing of natural gas. Beginning with the adoption of Order No. 436, issued in October 1985, the FERC has implemented a series of major restructuring orders that have required pipelines, among other things, to perform "open access" transportation of gas for others, "unbundle" their sales and transportation functions, and allow shippers to release their unneeded capacity temporarily and permanently to other shippers. As a result of these changes, sellers and buyers of gas have gained direct access to the particular pipeline services they need and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace. It remains to be seen, however, what effect the FERC's other activities will have on access to markets, the fostering of competition and the cost of doing business. We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities. We do not believe that we will be affected by any such new or different regulations materially differently than any other seller of natural gas with which we compete.

In the past, Congress has been very active in the area of gas regulation. However, as discussed above, the more recent trend has been in favor of deregulation, or "lighter handed" regulation, and the promotion of competition in the gas industry. There regularly are other legislative proposals pending in the Federal and state legislatures that, if enacted, would significantly affect the petroleum industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. Similarly, and despite the trend toward federal deregulation of the natural gas industry, whether or to what extent that trend will continue, or what the ultimate effect will be on our sales of gas, cannot be predicted. Again, we do not believe that we will be affected by any such new legislative proposals materially differently than any other seller of natural gas with which we compete.

We own certain natural gas pipelines that we believe meet the standards the FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction under the NGA. State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, nondiscriminatory take requirements, but does not generally entail rate regulation. Natural gas gathering may receive greater regulatory scrutiny at both state and federal levels in the post-restructuring environment.

Oil Price Controls and Transportation Rates. Sales of crude oil, condensate and gas liquids by us are not currently regulated and are made at market prices. The price we receive from the sale of these products may be affected by the cost of transporting the products to market. Much of the transportation is through interstate common carrier pipelines. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations have generally been approved on judicial review. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. The first such review was completed in 2000, and on December 14, 2000, FERC reaffirmed the current index. The FERC's regulation of oil transportation rates may tend to increase the cost of transporting oil and natural gas liquids by interstate pipelines, although the annual adjustments may result in decreased rates in a given year. Following a successful court challenge of these orders by an association of oil pipelines on February 24, 2003, the FERC acting on remand increased the index slightly for the current five-year period, effective July 2001. We are not able at this time to predict the effects of these regulations, if any, on the transportation costs associated with oil production from our oil producing operations.

Environmental Regulations. Our operations are subject to numerous federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences, 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 within wilderness, wetlands and other protected areas, require remedial measures to mitigate pollution from former operations, such as pit closure and plugging abandoned wells, and impose substantial liabilities for pollution resulting from production and drilling operations. Public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stricter environmental legislation and regulations applied to the oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly waste handling, disposal and cleanup requirements, our business and prospects could be adversely affected.

We generate wastes that may be subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The U.S. Environmental Protection Agency ("EPA") and various state agencies have limited the approved methods of disposal for certain hazardous and nonhazardous wastes. Furthermore, certain wastes generated by our oil and natural gas operations that are currently exempt from treatment as "hazardous wastes" may in the future be designated as "hazardous wastes," and therefore be subject to more rigorous and costly operating and disposal requirements.

We currently own or lease numerous properties that for many years have been used for the exploration and production of oil and natural gas. Although we believe that we have used good operating and waste disposal practices, prior owners and operators of these properties may not have used similar practices, and hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), RCRA and analogous state laws as well as state laws governing the management of oil and natural gas wastes. Under such laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

Our operations may be subject to the Clean Air Act ("CAA") and comparable state and local requirements. Amendments to the CAA were adopted in 1990 and contain provisions that have resulted in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and states developed and continue to develop regulations to implement these requirements. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. However, we do not believe our operations will be materially adversely affected by any such requirements.

Federal regulations require certain owners or operators of facilities that store or otherwise handle oil, such as Edge, to prepare and implement spill prevention, control, countermeasure ("SPCC") and response plans relating to the possible discharge of oil into surface waters. SPCC plans at our producing properties were developed and implemented in 1999. The Oil Pollution Act of 1990 ("OPA") contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities. Our operations are also subject to the federal Clean Water Act ("CWA") and analogous state laws. In accordance with the CWA, the state of Louisiana has issued regulations prohibiting discharges of produced water in state coastal waters effective July 1, 1997. Pursuant to other requirements of the CWA, the EPA has adopted regulations concerning discharges of storm water runoff. This program requires covered facilities to obtain individual permits, participate in a group permit or seek coverage under an EPA general permit. While certain of our properties may require permits for discharges of storm water runoff, we believe that we will be able to obtain, or be included under, such permits, where necessary, and make minor modifications to existing facilities and operations that would not have a material effect on us. Like OPA, the CWA and analogous state laws relating to the control of water pollution provide varying civil and criminal penalties and liabilities for releases of petroleum or its derivatives into surface waters or into the ground.

CERCLA, also known as the "Superfund" law, and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies, and 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.

We also are subject to a variety of federal, state and local permitting and registration requirements relating to protection of the environment. Management believes 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 effect on us.

OPERATING HAZARDS AND INSURANCE

The oil and natural gas business involves a variety of operating risks, including the risk of fire, explosion, blow-out, pipe failure, casing collapse, abnormally pressured formations and environmental hazards such as oil spills, natural gas leaks, ruptures and discharges of toxic gases, the occurrence of any of which could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, cleanup responsibilities, regulatory investigation and penalties and suspension of operations.

In accordance with customary industry practice, we maintain insurance against some, but not all, of the risks described above. Our insurance does not cover business interruption or protect against loss of revenue. There can be no assurance that any insurance obtained by us will be adequate to cover any losses or liabilities. We cannot predict the continued availability of insurance or the availability of insurance at premium levels that justify its purchase. The occurrence of a significant event not fully insured or indemnified against could materially and adversely affect our financial condition and operations.

RISK FACTORS

Oil and gas drilling is a speculative activity and involves numerous risks and substantial and uncertain costs which could adversely affect us.

Our growth will be materially dependent upon the success of our future drilling program. Drilling for oil and gas involves numerous risks, including the risk that no commercially productive oil or natural gas reservoirs will be encountered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors beyond our control, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions, compliance with governmental requirements and shortages or delays in the availability of drilling rigs or crews and the delivery of equipment. Our future drilling activities may not be successful and, if unsuccessful, such failure will have an adverse effect on our future results of operations and financial condition. Our overall drilling success rate or our drilling success rate for activity within a particular geographic area may decline. We may ultimately not be able to lease or drill identified or budgeted prospects within our expected time frame, or at all. We may not be able to lease or drill a particular prospect because, in some cases, we identify a prospect or drilling location before seeking an option or lease rights in the prospect or location. Similarly, our drilling schedule may vary from our capital budget. The final determination with respect to the drilling of any scheduled or budgeted wells will be dependent on a number of factors, including:

- the results of exploration efforts and the acquisition, review and analysis of the seismic data;
- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for oil and natural gas and the availability of drilling rigs and crews;
- our financial resources and results; and
- the availability of leases and permits on reasonable terms for the prospects.

These projects may not be successfully developed and the wells, if drilled, may not encounter reservoirs of commercially productive oil or natural gas. See *ITEM 7. "MANAGEMENT'S* DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – INDUSTRY AND ECONOMIC FACTORS" and *ITEMS 1 AND 2. "BUSINESS AND PROPERTIES* – CORE AREAS OF OPERATION."

Oil and natural gas prices are highly volatile in general and low prices negatively affect our financial results.

Our revenue, profitability, cash flow, future growth and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent upon prevailing prices of oil and natural gas. Our reserves are predominantly natural gas, therefore changes in natural gas prices may have a particularly large impact on our financial results. Lower oil and natural gas prices also may reduce the amount of oil and natural gas that we can produce economically. Historically, the markets for oil and natural gas have been volatile, and such markets are likely to continue to be volatile in the future. Prices for oil and natural gas are subject to wide fluctuation in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include the level of consumer product demand, weather conditions, domestic and foreign governmental regulations, the price and availability of alternative fuels, political conditions, the foreign supply of oil and natural gas, the price of foreign imports and overall economic conditions. Declines in oil and natural gas prices may materially adversely affect our financial condition, liquidity, and ability to finance planned capital expenditures and results of operations. See *ITEM 7. "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS* – DERIVATIVES AND HEDGING ACTIVITIES" *and ITEMS 1 AND 2. "BUSINESS AND PROPERTIES — OIL AND NATURAL GAS RESERVES" and "–* MARKETING."

We have in the past and may in the future be required to write down the carrying value of our oil and natural gas properties when oil and natural gas prices are depressed or unusually volatile. Whether we will be required to take such a charge will depend on the prices for oil and natural gas at the end of any quarter and the effect of reserve additions or revisions and capital expenditures during such quarter. If a write down is required, it would result in a charge to earnings and would not impact cash flow from operating activities.

We have hedged and may continue to hedge a portion of our production, which may result in our making cash payments or prevent us from receiving the full benefit of increases in prices for oil and gas.

In order to reduce our exposure to short-term fluctuations in the price of oil and natural gas, we periodically enter into hedging arrangements. Our hedging arrangements apply to only a portion of our production and provide only partial price protection against declines in oil and natural gas prices. Such hedging arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected, our customers fail to purchase contracted quantities of oil or natural gas or a sudden, unexpected event materially impacts oil or natural gas prices. In addition, our hedging arrangements may limit the benefit to us of increases in the price of oil and natural gas. See *ITEM 7. "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS* – DERIVATIVES AND HEDGING ACTIVITIES " and *ITEMS 1 AND 2. "BUSINESS AND PROPERTIES* – MARKETING."

We depend on successful exploration, development and acquisitions to maintain reserves and revenue in the future.

In general, the volume of production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Except to the extent we acquire properties containing proved reserves or conduct successful exploration and development activities, or both, our proved reserves will decline. Our future oil and natural gas production is, therefore, highly dependent upon our level of success in finding or acquiring additional reserves. In addition, we are dependent on finding partners for our exploratory activity. To the extent that others in the industry do not have the financial resources or choose not to participate in our exploration activities, we could be adversely affected.

We are subject to substantial operating risks that may adversely affect the results of our operations.

The oil and natural gas business involves certain operating hazards such as well blowouts, mechanical failures, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, formations with abnormal pressures, pollution, releases of toxic gas and other environmental hazards and risks. We could suffer substantial losses as a result of any of these events. We are not fully insured against all risks incident to our business.

We are not the operator of some of our wells. As a result, our operating risks for those wells and our ability to influence the operations for these wells are less subject to our control. Operators of these wells may act in ways that are not in our best interests. See *ITEMS 1 AND 2. "BUSINESS AND PROPERTIES* – OPERATING HAZARDS AND INSURANCE."

We cannot control the activities on properties we do not operate and are unable to ensure their proper operation and profitability.

We do not operate all of the properties in which we have an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, operations of these properties. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interest could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors outside of our control, including the operator's

- timing and amount of capital expenditures;
- expertise and financial resources;
- inclusion of other participants in drilling wells; and
- use of technology.

The loss of key personnel could adversely affect us.

We depend to a large extent on the services of certain key management personnel, including our executive officers and other key employees, the loss of any of which could have a material adverse effect on our operations. We do not maintain key-man life insurance with respect to any of our employees. We believe that our success is also dependent upon our ability to continue to employ and retain skilled technical personnel. See *ITEMS 1 AND 2. "BUSINESS AND PROPERTIES – TECHNOLOGY."*

Our operations have significant capital requirements which, if not met, will hinder operations.

We have experienced and expect to continue to experience substantial working capital needs due to our active exploration, development and acquisition programs. Additional financing may be required in the future to fund our growth. We may not be able to obtain such additional financing and financing under existing or new credit facilities may not be available in the future. In the event such capital resources are not available to us, our drilling and other activities may be curtailed. See *ITEM 7. "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS* – LIQUIDITY AND CAPITAL RESOURCES."

Government regulation and liability for environmental matters may adversely affect our business and results of operations.

Oil and natural gas operations are subject to various federal, state and local government regulations, which may be changed from time to time. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity in order to conserve supplies of oil and natural gas. There are federal, state and local laws and regulations primarily relating to protection of human health and the environment applicable to the development, production, handling, storage, transportation and disposal of oil and natural gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations. In addition, we may be liable for environmental damages caused by previous owners of property we purchase or lease. As a result, we may incur substantial liabilities to third parties or governmental entities. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted. The implementation of new, or the modification of existing, laws or regulations could have a material adverse effect on us. See *ITEMS 1 AND 2. "BUSINESS AND PROPERTIES* – INDUSTRY REGULATIONS."

We may have difficulty managing any future growth and the related demands on our resources and may have difficulty in achieving future growth.

We have experienced growth in the past through the expansion of our drilling program and, more recently, acquisitions. This expansion was curtailed in 1998 and 1999, but resumed in 2000 and increased in subsequent years. Further expansion is anticipated in 2005 both through increased drilling efforts and possible acquisitions. Any future growth may place a significant strain on our financial, technical, operational and administrative resources. Our ability to grow will depend upon a number of factors, including our ability to identify and acquire new exploratory prospects, our ability to develop existing prospects, our ability to continue to retain and attract skilled personnel, the results of our drilling program and acquisition efforts, hydrocarbon prices and access to capital. We may not be successful in achieving or managing growth and any such failure could have a material adverse effect on us.

We face strong competition from larger oil and natural gas companies.

The oil and gas industry is highly competitive. We encounter competition from oil and natural gas companies in all areas of our operations, including the acquisition of exploratory prospects and productive oil and natural gas properties. Our competitors range in size from the major integrated oil and natural gas companies to numerous independent oil and natural gas companies, individuals and drilling and income programs. Many of these competitors are large, well-established companies with substantially larger operating staffs and greater capital resources than us. We may not be able to successfully conduct our operations, evaluate and select suitable properties, consummate transactions, and obtain technical, managerial and other professional personnel in this highly competitive environment. Specifically, these larger competitors may be able to pay more for exploratory prospects, productive oil and natural gas properties and competent personnel and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, such competitors may be able to expend greater resources on the existing and changing technologies that we believe are and will be increasingly important to attaining success in the industry. See *ITEMS 1 AND 2. "BUSINESS AND PROPERTIES* – COMPETITION."

The oil and natural gas reserve data included in or incorporated by reference in this document are estimates based on assumptions that may be inaccurate and existing economic and operating conditions that may differ from future economic and operating conditions.

Reservoir engineering is a subjective and inexact process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner and is based upon assumptions that may vary considerably from actual results. Accordingly, reserve estimates may be subject to downward or upward adjustment. Actual production, revenue and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material. The information regarding discounted future net cash flows included in this report should not be considered as the current market value of the estimated oil and natural gas reserves attributable to our properties. As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as the amount and timing of actual production, supply and demand for oil and natural gas, increases or decreases in consumption, and changes in governmental regulations or taxation. In addition, the 10% discount factor, which is required by Financial Accounting Standards Board in Statement of Financial Accounting Standards No. 69, "*Disclosures About Oil and Natural Gas Producing Activities*" to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. See *ITEMS 1 AND 2. "BUSINESS AND PROPERTIES* - OIL AND NATURAL GAS RESERVES."

Our credit facility has substantial operating restrictions and financial covenants and we may have difficulty obtaining additional credit, which could adversely affect operations.

Over the past few years, increases in commodity prices, in proved reserve amounts and the resultant increase in estimated discounted future net revenue, has allowed us to increase our available borrowing amounts. In the future, commodity prices may decline, we may increase our borrowings or our borrowing base may be adjusted downward. Our credit facility is secured by a pledge of substantially all of our assets and has covenants that limit additional borrowings, sales of assets and the distributions of cash or properties and that prohibit the payment of dividends and the incurrence of liens. The revolving credit facility also requires that specified financial ratios be maintained. The restrictions of our credit facility and the difficulty in obtaining additional debt financing may have adverse consequences on our operations and financial results, including our ability to obtain financing for working capital, capital expenditures, our drilling program, purchases of new technology or other purposes. In addition, such financing may be on terms unfavorable to us and we may be required to use a substantial portion of our cash flow to make debt service payments, which will reduce the funds that would otherwise be available for operations and future business opportunities. Further, a substantial decrease in our operating cash flow or an increase in our expenses could make it difficult for us to meet debt service requirements and require us to modify operations and we may become more vulnerable to downturns in our business or the economy generally.

Our ability to obtain and service indebtedness will depend on our future performance, including our ability to manage cash flow and working capital, which are in turn subject to a variety of factors beyond our control. Our business may not generate cash flow at or above anticipated levels or we may not be able to borrow funds in amounts sufficient to enable us to service indebtedness, make anticipated capital expenditures or finance our drilling program. If we are unable to generate sufficient cash flow from operations or to borrow sufficient funds in the future to service our debt, we may be required to curtail portions of our drilling program, sell assets, reduce capital expenditures, refinance all or a portion of our existing debt or obtain additional financing. We may not be able to refinance our debt or obtain additional financing, particularly in view of current industry conditions, the restrictions on our ability to incur debt under our existing debt arrangements, and the fact that substantially all of our assets are currently pledged to secure obligations under our bank credit facility. See *ITEM 7. "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS* - LIQUIDITY AND CAPITAL RESOURCES" *and "- CREDIT FACILITY."*

We may not have enough insurance to cover all of the risks we face.

In accordance with customary industry practices, we maintain insurance coverage against some, but not all, potential losses in order to protect against the risks we face. We do not carry business interruption insurance. We may elect not to carry insurance if our management believes that the cast of available insurance is excessive relative to the risks presented. In addition, we cannot insure fully against pollution and environmental risks. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial condition and results of operations.

Our acquisition program may be unsuccessful.

Acquisitions have become increasingly important to our business strategy in recent years. The successful acquisition of producing properties requires an assessment of recoverable reserves, future oil and natural gas prices, operating costs, potential environmental and other liabilities and other factors. Such assessments, even when performed by experienced personnel, are necessarily inexact and their accuracy inherently uncertain. Our review of subject properties will not reveal all existing or potential problems, deficiencies and capabilities. We may not always perform inspections on every well, and may not be able to observe structural and environmental problems even when we undertake an inspection. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of such problems. Any acquisition of property interests by us may not be successful and, if unsuccessful, such failure may have an adverse effect on our future results of operations and financial condition.

We do not intend to pay dividends and our ability to pay dividends is restricted.

We currently intend to retain any earnings for the future operation and development of our business and do not currently anticipate paying any dividends in the foreseeable future. We are currently restricted from paying dividends by our existing credit facility agreement. Any future dividends also may be restricted by our then-existing loan agreements. See *ITEM 7. "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – LIQUIDITY AND CAPITAL RESOURCES*" and Note 10 to our consolidated financial statements.

Our reliance on third parties for gathering and distributing could curtail future exploration and production activities.

The marketability of our production depends upon the proximity of our reserves to, and the capacity of, facilities and third party services, including oil and natural gas gathering systems, pipelines, trucking or terminal facilities, and processing facilities. The unavailability or lack of capacity of such services and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. A shut-in or delay or discontinuance could adversely affect our financial condition. In addition, federal and state regulation of oil and natural gas production and transportation affect our ability to produce and market our oil and natural gas on a profitable basis.

Provisions of Delaware law and our charter and bylaws may delay or prevent transactions that would benefit stockholders.

Our Certificate of Incorporation and Bylaws and the Delaware General Corporation Law contain provisions that may have the effect of delaying, deferring or preventing a change of control of the company. These provisions, among other things, provide for a classified Board of Directors with staggered terms, restrict the ability of stockholders to take action by written consent, authorize the Board of Directors to set the terms of Preferred Stock, and restrict our ability to engage in transactions with 15% stockholders.

Because of these provisions, persons considering unsolicited tender offers or other unilateral takeover proposals may be more likely to negotiate with our board of directors rather than pursue non-negotiated takeover attempts. As a result, these provisions may make it more difficult for our stockholders to benefit from transactions that are opposed by an incumbent board of directors.

Miller's former use of Arthur Andersen LLP as its independent public accountants may limit your ability to seek potential recoveries from them related to their work.

Arthur Andersen LLP, independent public accountants, audited the consolidated balance sheet of Miller and its subsidiary as of December 31, 2001, and the related consolidated statements of operations, equity and cash flows for the year ending December 31, 2001. On June 15, 2002, Arthur Andersen was convicted on a federal obstruction of justice charge. On June 27, 2002, Miller dismissed Arthur Andersen and engaged Plante & Moran, PLLC. Arthur Andersen has ceased operations. As a result, any recovery any Edge stakeholder may have from Arthur Andersen related to the claims that such stakeholder may assert related to the financial statements audited by Arthur Andersen, misstatements or omissions, if any, in this Form 10-K, will be limited by the financial circumstances of Arthur Andersen.

AVAILABLE INFORMATION

Our website address is www.edgepet.com We make our website content available for information purposes only. It should not be relied upon for investment purposes, nor is it incorporated by reference in this Form 10-K. We make available on this website under "Investor Information-Financials/SEC Flings," free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the SEC. The SEC also maintains a website at www.sec.gov that contains reports, proxy statements and other information regarding SEC registrants, including us.

CERTAIN DEFINITIONS

The definitions set forth below shall apply to the indicated terms as used in this Form 10-K. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

After payout. With respect to an oil or natural gas interest in a property, refers to the time period after which the costs to drill and equip a well have been recovered.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Bbls/d. Stock tank barrels per day.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Before payout. With respect to an oil and natural gas interest in a property, refers to the time period before which the costs to drill and equip a well have been recovered.

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.

Developed acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed the related oil and natural gas operating expenses and taxes.

Exploratory well. A well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

Farm-in or farm-out. An agreement whereunder the owner of a working interest in an oil and natural gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty and/or reversionary interest in the lease. The interest received by an assignee is a "farm-in" while the interest transferred by the assignor is a "farm-out."

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Finding costs. Costs associated with acquiring and developing proved oil and natural gas reserves which are capitalized by us pursuant to generally accepted accounting principles in the United States, including all costs involved in acquiring acreage, geological and geophysical work and the cost of drilling and completing wells, excluding those costs attributable to unproved property.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet.

Mcf/d. One thousand cubic feet per day.

Mcfe. One thousand cubic feet equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids, which approximates the relative energy content of crude oil, condensate and natural gas liquids as compared to natural gas. Prices have historically been higher or substantially higher for crude oil than natural gas on an energy equivalent basis although there have been periods in which they have been lower or substantially lower.

MMcf. One million cubic feet.

MMcfe. One million cubic feet equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids, which approximates the relative energy content of crude oil, condensate and natural gas liquids as compared to natural gas.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells.

NGL's. Natural gas liquids measured in barrels.

NRI or Net Revenue Interests. The share of production after satisfaction of all royalty, overriding royalty, oil payments and other nonoperating interests.

Normally pressured reservoirs. Reservoirs with a formation-fluid pressure equivalent to 0.465 PSI per foot of depth from the surface. For example, if the formation pressure is 4,650 PSI at 10,000 feet, then the pressure is considered to be normal.

Over-pressured reservoirs. Reservoirs subject to abnormally high pressure as a result of certain types of subsurface formations.

Petrophysical study. Study of rock and fluid properties based on well log and core analysis.

Plant Products. Liquids generated by a plant facility and include propane, iso-butane, normal butane, pentane and ethane.

Present value. When used with respect to oil and natural gas reserves, the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date indicated, without giving effect to nonproperty-related expenses such as general and administrative expenses, debt service and future income tax expense or to depletion, depreciation, and amortization, discounted using an annual discount rate of 10%.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes.

Proved developed nonproducing reserves. Proved developed reserves expected to be recovered from zones behind casing in existing wells.

Proved developed producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and able to produce to market.

Proved developed reserves. Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Proved reserves. The estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

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

Recompletion. The completion for production of an existing well bore in another formation from that in which the well has been previously completed.

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.

Royalty interest. An interest in an oil and natural gas property entitling the owner to a share of oil or natural gas production free of costs of production.

3-D seismic. Advanced technology method of detecting accumulations of hydrocarbons identified through a three-dimensional picture of the subsurface created by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working interest or WI. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover. Operations on a producing well to restore or increase production.

ITEM 3. LEGAL PROCEEDINGS

From time to time we are a party to various legal proceedings arising in the ordinary course of business. While the outcome of lawsuits cannot be predicted with certainty, we are not currently a party to any proceeding that we believe, if determined in a manner adverse to us, could have a potential material adverse effect on our financial condition, results of operations or cash flows.

During the second quarter of 2004, the Company received notice that its franchise tax returns for the State of Texas would be audited for the tax years 1999 through 2002. After reviewing documents submitted, the agent representing the Office of the Comptroller of the State of Texas proposed adjustments to the calculation that would result in an increased franchise tax liability. The agent maintained that transfers by the parent company to its subsidiaries that the Company classified as intercompany loans should instead be classified as equity investments in the subsidiary. The State of Texas originally proposed that the franchise tax liability of the subsidiaries would be increased by approximately $3.0 million for the four-year period under audit.

During the third quarter of 2004 the agent reduced the proposed franchise tax deficiency adjustment to the Company and its subsidiaries to an aggregate of $467,000. In the fourth quarter of 2004, there was an informal hearing at the local Comptroller's Office during which the agent indicated he would formally assess the proposed deficiency. The Company has not received any such deficiency assessment, but if it does, it intends to continue to vigorously contest the assessment through appropriate administrative levels in the Comptroller's Office and any other available means. Due to its intention to continue to vigorously contest the proposed adjustments, the Company has not recognized any provision for the additional franchise taxes that would result from the proposed deficiency.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

NONE.

Executive Officers of the Registrant

Pursuant to Instruction 3 to Item 401(b) of Regulation S-K and General Instruction G (3) to Form 10-K the following information is included in Part I of this Form 10-K.

John W. Elias has served as the Chief Executive Officer and Chairman of the Board of the Company since November 1998. From April 1993 to September 30, 1998, he served in various senior management positions, including Executive Vice President, of Seagull Energy Corporation, a company engaged in oil and natural gas exploration, development and production and pipeline marketing. Prior to April 1993, Mr. Elias served in various positions for more than 30 years, including senior management positions with Amoco Corporation, a major integrated oil and gas company. Mr. Elias has more than 40 years of experience in the oil and natural gas exploration and production business. He is 64 years old.

Michael G. Long has served as Senior Vice President and Chief Financial Officer of the Company since December 1996 and as Treasurer of the Company since October 2004. Mr. Long served as Vice President-Finance of W&T Offshore, Inc., an oil and natural gas exploration and production company, from July 1995 to December 1996. From May 1994 to July 1995, he served as Vice President of the Southwest Petroleum Division for Chase Manhattan Bank, N.A. Prior thereto, he served in various capacities with First National Bank of Chicago, most recently that of Vice President and Senior Corporate Banker of the Energy and Transportation Department, from March 1992 to May 1994. Mr. Long received a B.A. in Political Science and a M.S. in Economics from the University of Illinois. Mr. Long is 52 years old.

John O. Tugwell has served as Chief Operating Officer since March 2004 and Senior Vice President Production since December 2001 and prior to that served as Vice President of Production for the Company since March 1997. He served as Senior Petroleum Engineer of the Company's predecessor corporation since May 1995. From 1986 to May 1995, he held various reservoir/production engineering positions with Shell Oil Company, most recently that of Senior Reservoir Engineer. Mr. Tugwell holds a B.S. in Petroleum Engineering from Louisiana State University. Mr. Tugwell is a registered Professional Engineer in the State of Texas. Mr. Tugwell is 41 years old.

Significant Employees

Mark J. Gabrisch has served as the Vice President of Land for the Company since March 1997. From November 1994 to March 1997, he served in a similar capacity with the Company's predecessor corporation. From 1985 to October 1994, he was a landman, most recently a Senior Landman, for Shell Oil Company. Mr. Gabrisch holds a B.S. in Petroleum Land Management from the University of Houston. Mr. Gabrisch is 44 years old.

John O. Hastings, Jr. has served as the Vice President of Exploration for the Company since March 1997 and prior thereto served in a similar capacity with the Company's predecessor corporation since February 1994. From 1984 to February 1994, he was an exploration geologist with Shell Oil Company, serving as Senior Geologist before his departure. Mr. Hastings holds a B.A. from Dartmouth in Earth Sciences and a M.S. in Geology from Texas A&M University. He is 45 years old.

Kirsten A. Hink has served as Vice President & Controller of the Company since October 1, 2003 and as Controller of the Company since December 31, 2000. Prior to that time she served as Assistant Controller from June 2000 to December 2000. Before joining Edge, she served as Controller of Benz Energy Inc., an oil and gas exploration company, from June 1998 to June 2000. Mrs. Hink received a B.S. in Accounting from Trinity University. Mrs. Hink is a Certified Public Accountant in the State of Texas. She is 38 years old.

James D. Keisling has served as Vice President Production for the Company since April 2004. From May 2000 to April 2004, he served as Chief Engineer for the Company. From August 1989 to April 2000, he served as Production Manager of Ocean Energy, Inc., serving as Southern Region Production Manager before his departure. Mr. Keisling holds a B.S. degree in Civil Engineering from New Mexico State University. Mr. Keisling is a registered professional engineer in the state of Texas. He is 57 years old.

C.W. MacLeod has served as the Senior Vice President Business Development and Planning for the Company since April 2004 and Vice President Business Development and Planning for the Company since January 2002. From November 1999 to December 2001, he was Vice President - Investment Banking with Raymond James and Associates, Inc. From February 1990 to October 1999, Mr. MacLeod was a principal with Kirkpatrick Energy Associates, Inc., whose principal business was merger and acquisition services, capital arrangement and analytical services for the oil and gas producing industry. Mr. MacLeod was responsible for originating corporate finance and research products for energy clients. His previous experience includes positions as an independent petroleum geologist, a manager of exploration and production for an independent oil and gas producer and geologic positions with Ladd Petroleum Corporation and Resource Sciences Corporation. Mr. MacLeod graduated from Eastern Michigan University with a B.S. in Geology and earned his M.B.A. from the University of Tulsa. Mr. MacLeod is a registered professional geologist in the state of Wyoming. He is 54 years old.

Robert C. Thomas has served as Vice President, General Counsel and Corporate Secretary since March 1997. From February 1991 to March 1997, he served in similar capacities for the Company's corporate predecessor. From 1988 to January 1991, he was associate and acting general counsel for Mesa Limited Partnership in Amarillo, Texas. Mr. Thomas holds a B.S. degree in Finance and a J.D. degree in Law from the University of Texas at Austin. He is 51 years old.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Price of and Dividends on Common Equity and Related Stockholder Matters.

As of March 11, 2005, we estimate there were approximately 268 beneficial holders of our Common Stock. Our Common Stock is listed on the NASDAQ National Market ("NASDAQ") and traded under the symbol "EPEX". As of March 11, 2005, we had 17,100,155 shares outstanding and our closing price on NASDAQ was $16.27 per share. The following table sets forth, for the periods indicated, the high and low closing sales prices for our Common Stock as listed on NASDAQ.

	Common Stock Prices	
	High ($)	**Low ($)**
Calendar 2004		
First Quarter	14.61	8.67
Second Quarter	17.04	12.50
Third Quarter	19.24	13.26
Fourth Quarter	17.49	13.43
Calendar 2003		
First Quarter	4.47	3.72
Second Quarter	6.15	3.82
Third Quarter	7.00	4.85
Fourth Quarter	11.20	6.37

We have never paid a dividend, cash or otherwise, and do not intend to in the foreseeable future. In addition, under our current credit facility, we are restricted from paying cash dividends on our Common Stock. The payment of future dividends, if any, will be determined by our Board of Directors in light of conditions then existing, including our earnings, financial condition, capital requirements, restrictions in financing agreements, business conditions and other factors. See *ITEMS 1 AND 2. "BUSINESS AND PROPERTIES* – RISK FACTORS – We do not intend to pay dividends and our ability to pay dividends is restricted."

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected financial data regarding the Company as of and for each of the periods indicated. The following data should be read in conjunction with *ITEM 7. "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS"* and our financial statements and notes thereto included in ITEM 8:

	Year Ended December 31,				
	2004 (1)	2003(2)	2002	2001 (3)	2000
	(in thousands, except per share amounts)				
Statement of operations:					
Oil and natural gas revenue	$ 64,505	$ 33,926	$ 20,911	$ 29,811	$ 23,774
Operating expenses:					
Oil and natural gas operating expenses including production and ad valorem taxes	9,309	5,116	3,831	5,001	3,955
Depletion, depreciation, amortization and accretion (2)	21,928	13,577	10,427	9,378	7,641
Litigation settlement	--	--	--	3,547	--
General and administrative expenses:					
Deferred compensation expense – repriced options (4)	1,136	1,219	4	(850)	899
Deferred compensation expense – restricted stock	498	372	399	353	128
Other general and administrative	7,813	5,541	4,826	5,038	3,824
Total operating expenses	40,684	25,825	19,487	22,467	16,447
Operating income	23,821	8,101	1,424	7,344	7,327
Interest expense and amortization of deferred loan costs, net of amounts capitalized	(473)	(679)	(228)	(215)	(172)
Interest income	36	17	27	128	98
Loss on sale of investment	--	--	--	--	(355)
Income before income taxes and cumulative effect of accounting change	23,384	7,439	1,223	7,257	6,898
Income tax (expense) benefit	(8,255)	(2,731)	(473)	819	--
Income before cumulative effect of accounting change	15,129	4,708	750	8,076	6,898
Cumulative effect of accounting change (2)	--	(358)	--	--	--
Net income	$ 15,129	$ 4,350	$ 750	$ 8,076	$ 6,898
Basic earnings per share:					
Income before cumulative effect of accounting change	$ 1.16	$ 0.48	$ 0.08	$ 0.87	$ 0.75
Cumulative effect of accounting change	--	(0.03)	--	--	--
Basic earnings per share	$ 1.16	$ 0.45	$ 0.08	$ 0.87	$ 0.75
Diluted earnings per share:					
Income before cumulative effect of accounting change	$ 1.11	$ 0.47	$ 0.08	$ 0.83	$ 0.74
Cumulative effect of accounting change	--	(0.03)	--	--	--
Diluted earnings per share	$ 1.11	$ 0.44	$ 0.08	$ 0.83	$ 0.74
Basic weighted average number of shares outstanding (5)	13,029	9,726	9,384	9,281	9,183
Diluted weighted average number of shares outstanding (5)	13,648	9,988	9,606	9,728	9,330
EBITDA Reconciliation (6):					
Net income	$ 15,129	$ 4,350	$ 750	$ 8,076	$ 6,898
Cumulative effect of accounting change (2)	--	358	--	--	--
Income tax (expense) benefit	8,255	2,731	473	819	--
Interest expense and amortization of deferred loan costs, net of amounts capitalized	473	679	228	215	172
Interest income	(36)	(17)	(27)	(128)	(98)
Depletion, depreciation, amortization and accretion (2)	21,928	13,577	10,427	9,378	7,641
EBITDA	$ 45,749	$ 21,678	$ 11,851	$ 16,722	$ 14,613

	As of December 31,				
	2004 (1)	2003 (2)	2002	2001 (3)	2000
			(in thousands)		
Selected Cash Flow Data:					
Net cash provided by operating activities	$ 42,270	$ 23,898	$ 10,408	$ 22,151	$ 9,646
Capital expenditures	$ (89,470)	$ (33,560)	$ (19,610)	$ (28,989)	$ (10,718)
Other investing activities	60	5,490	355	--	5,323
Net cash used in investing activities	$ (89,410)	$ (28,070)	$ (19,255)	$ (28,989)	$ (5,395)
Net cash provided by (used in) financing activities	$ 48,080	$ 2,931	$ 10,623	$ 7,383	$ (4,003)
Selected Balance Sheet Data:					
Working capital	$ 8,957	$ 948	$ 3,310	$ 682	$ 2,879
Property and equipment, net	165,840	97,981	75,682	66,853	47,242
Total assets	191,950	118,012	85,576	76,024	57,961
Long-term debt, including current maturities	20,000	21,000	20,500	10,000	3,000
Stockholders' equity (5)	150,467	82,011	58,533	58,099	50,129

(1) As discussed in Note 6 to our consolidated financial statements, we completed the merger with Miller in December 2003, this affects the comparability of our results in 2004 to other periods presented.

(2) As discussed in Note 2 to our consolidated financial statements, effective January 1, 2003, we changed our method of accounting for asset retirement obligations, this affects the comparability of our results in 2004 and 2003 to other periods presented.

(3) As discussed in Note 2 to our consolidated financial statements, effective January 1, 2001, we changed our method of accounting for derivative instruments, this affects the comparability of our results in 2001 through 2004 to 2000.

(4) Deferred compensation expense includes the non-cash charge or credit related to FASB Interpretation No. ("FIN") 44, "*Accounting for Certain Transactions involving Stock Compensation.*" In May 1999, certain outstanding options were re-priced, which triggered the FIN 44 requirement of variable accounting for modifications in the terms of those stock options (see Note 2 to our consolidated financial statements). Each period can be impacted by (i) re-priced options that are exercised and (ii) the change in the value of outstanding repriced options based on the price of our common stock at period-end. Volatility in our stock price can have a significant impact on this amount from period to period, which may affect the comparability of our results for the periods presented.

(5) As discussed in Note 11 to our consolidated financial statements, we completed a public offering of our common stock on December 21, 2004 and a significant property acquisition on December 29, 2004, therefore certain of our results in 2004 are not directly comparable to other periods.

(6) EBITDA is defined as net income (loss) before cumulative effect of accounting change, interest expense and amortization of deferred loan costs (net of interest income and amounts capitalized), income tax expense, depletion, depreciation and amortization and accretion expense. EBITDA is not defined under accounting principles generally accepted in the United States of America ("GAAP"). EBITDA is a financial measure commonly used in the oil and natural gas industry and should not be considered in isolation or as a substitute for net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP or as a measure of a company's profitability or liquidity. Because EBITDA excludes some, but not all, items that affect net income, this measure may vary among companies. The EBITDA data presented above may not be comparable to a similarly titled measure of other companies. Our management believes that EBITDA is a meaningful measure to investors and may provide additional information about our ability to meet our future liquidity requirements.

We do not pay cash dividends and have not in the periods presented above, therefore they are not presented in the selected financial data.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is a review of our financial position and results of operations for the periods indicated. Our Consolidated Financial Statements and Supplementary Information and the related notes thereto contain detailed information that should be referred to in conjunction with Management's Discussion and Analysis ("MD&A") of Financial Condition and Results of Operations.

GENERAL OVERVIEW

Edge Petroleum Corporation ("Edge" or the "Company") is a Houston-based independent energy company that focuses its exploration, production and marketing activities in selected onshore basins of the United States. In late 1998, we undertook a top-level management change and began a shift in strategy from pure exploration, which focused more on prospect generation, to our current strategy which focuses on a balanced program of exploration, exploitation and development and acquisition of oil and gas properties. Our company generates revenues, income and cash flows by producing and marketing oil and natural gas produced from our oil and natural gas properties. We make significant capital expenditures in our exploration, development, and acquisition activities that allow us to continue generating revenue, income and cash flows. In December 2003, we acquired 100 percent of the outstanding stock of Miller Exploration Company ("Miller"). The transaction was treated as a tax-free reorganization and accounted for as a purchase business combination. Miller continues to conduct exploration and development activities as a wholly-owned subsidiary of Edge. In December 2004, we acquired substantially all of the operating assets of Contango Oil & Gas Company ("Contango") for a cash purchase price, financed by proceeds from a public offering of our common stock. This acquisition is hereinafter referred to as the Contango Asset Acquisition.

This overview provides our perspective on the individual sections of MD&A, as well as helpful hints for reading these pages. Our MD&A includes the following sections:

- **Industry and Economic Factors** – a general description of value drivers of our business as well as opportunities, challenges and risks related to the oil and gas industry.
- **Approach to the Business** – additional information regarding our approach and strategy.
- **Acquisitions and Divestitures** - information about significant changes in our business structure.
- **Outlook** – additional discussion relating to management's outlook to the future of our business.
- **Critical Accounting Policies and Estimates** – a discussion of certain accounting policies that require critical judgments and estimates.
- **Results of Operations** – an analysis of our Company's consolidated results for the periods presented in our financial statements.
- **Liquidity and Capital Resources** - an analysis of cash flows, sources and uses of cash, and contractual obligations.
- **Risk Management Activities – Derivatives & Hedging** – supplementary information regarding our Company's price-risk management activities involving commodity contracts that are accounted for at fair value.
- **Tax Matters** – supplementary discussion of income tax matters.
- **Recently Issued Accounting Pronouncements** – a discussion of certain accounting pronouncements recently issued that may impact our future results.

Industry and Economic Factors

In managing our business, we must deal with many factors inherent in our industry. First and foremost is the fluctuation of oil and gas prices. Historically, oil and gas markets have been cyclical and volatile, with future price movements, which are difficult to predict. While our revenues are a function of both production and prices, it is wide swings in prices that have most often had the greatest impact on our results of operations. We have no way to predict those prices or to control them without losing some advantage of the upside potential.

Our operations entail significant complexities. Advanced technologies requiring highly trained personnel are utilized in both exploration and production. Even when the technology is properly used, we may still not know conclusively if hydrocarbons will be present or the rate at which they will be produced. Exploration is a high-risk activity, often times resulting in no commercially productive reserves being discovered. Moreover, costs associated with operating within our industry are substantial.

Our business, as with other extractive industries, is a depleting one in which each gas equivalent produced must be replaced or we, and a critical source of our future liquidity, will shrink.

The oil and gas industry is highly competitive. We compete with major and diversified energy companies, independent oil and gas businesses and individual operators in exploration, production, marketing and acquisition activities. In addition, the industry as a whole competes with other businesses that supply energy to industrial and commercial end users.

Extensive federal, state and local regulation of the industry significantly affects our operations. In particular, our activities are subject to stringent environmental regulations. These regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning oil and gas wells and related facilities. These regulations may become more demanding in the future.

Approach to the Business

Profitable growth of our business will largely depend upon our ability to successfully find and develop new proved reserves of oil and natural gas in a cost-effective manner. In order to achieve an overall acceptable rate of growth, we seek to maintain a prudent blend of low, moderate and higher risk exploration and development projects. We also attempt to make selected acquisitions of oil and gas properties to augment our growth and provide future drilling opportunities. To further mitigate risk, we have chosen to seek geologic and geographic diversification by operating in multiple basins. We periodically hedge our exposure to volatile oil and gas prices on a portion of our production to manage price risk. As of December 31, 2004, we have entered into hedge contracts covering approximately 50% and 30% of our anticipated 2005 natural gas and crude oil production, respectively, before any acquisitions.

Implementation of our business approach relies on our ability to fund ongoing exploration and development projects with cash flow provided by operating activities and external sources of capital. In late 2003, we announced plans for record capital expenditures of approximately $28 million for 2004, which was subsequently expanded to $52 million. Our Board recently approved a 2005 capital budget of $63 million. Based on current expectations for production volumes and commodity prices, we expect to fund those capital expenditures from internally generated cash from operating activities. We do not typically include acquisitions in our budgeted capital expenditures, but expect to fund those with either borrowings under our credit facility or offerings of common stock or other securities under our shelf registration statement or other sources.

In 2004, Edge reported a 39% increase in proved reserves over the 2003 period, including the effect of the Contango Asset Acquisition (see Acquisitions and Divestitures below), and a 49% increase in annual production volumes over the 2003 period. We also replaced 308% of our total 2004 production (see *ITEMS 1 AND 2. "BUSINESS AND PROPERTIES* – Oil and Natural Gas Reserve Replacement." Production in the fourth quarter was 15% higher than in the previous quarter and we exited 2004 with a record daily production rate of 49.1 MMcfe/D as compared to 32.0 MMcfe/D a year ago. We believe that a strong financial position as represented by a debt to total capital ratio of 11.7%, available unused borrowing capacity and increased cash flow from our growing production volumes as a result of successful drilling and the Contango Asset Acquisition completed in December 2004 will help lay the ground work for our activities in 2005. Operationally and financially, we believe we are well positioned to continue the execution of our business strategy during 2005.

Acquisitions and Divestitures

Acquisitions - We have become increasingly active in acquisitions in recent years. We have looked to acquisitions to enable us to achieve our desired growth and we expect acquisitions will continue to play a significant role in our future plans for growth.

On December 4, 2003, we completed our acquisition of Miller. Miller was an independent oil and gas exploration and production company with exploration efforts concentrated primarily in the Mississippi Salt Basin of central Mississippi. Under the terms of the merger agreement, each share of issued and outstanding common stock of Miller was converted into 1.22342 shares of Edge common stock. We issued approximately 2.6 million shares of Edge common stock to the shareholders of Miller in exchange for all of the outstanding common stock of Miller. The merger was treated as a tax-free reorganization and accounted for as a purchase business combination under generally accepted accounting principles. We operate the majority of the acquired properties. We acquired Miller for the development and exploitation projects in Miller's core area, increased financial flexibility, and expansion of our core areas. During 2004, we realized much of the exploitable potential of the Miller properties and will continue to focus on these opportunities in 2005.

On October 7, 2004, we executed an Asset Purchase Agreement to acquire oil and natural gas properties located in south Texas from Contango for a cash purchase price of approximately $50 million. The purchase price was subject to adjustment for the results of operations between the July 1, 2004 effective date and the December 29, 2004 closing date. The purchase price was preliminarily adjusted to $43.2 million at closing for the results of operations between the July 1, 2004 effective date and October 31, 2004. In addition, at December 31, 2004 a further downward adjustment of $3.4 million was accrued for the results of operations for November 1, 2004 through December 29, 2004, which we anticipate realizing in March 2005, pursuant to the post-closing adjustments provision. We financed the acquisition with proceeds from a public offering of our common stock under our current shelf registration (see Note 11 to our consolidated financial statements). The properties acquired consist of 39 non-operated producing wells with working interests ranging from approximately 41% to 75% and net revenue interests ranging from 29% to 56%. These properties, located primarily in Jim Hogg County, Texas and producing primarily from the Queen City formation, are in a geographic area that has been one of our most active and successful areas of focus in recent years. In addition to estimated proved reserves, our technical team has also identified a substantial number of additional drilling locations on undeveloped acreage with attractive exploitation and exploration potential; therefore, we allocated $6 million of the purchase price to the unproved property category.

Divestitures - We regularly review our asset base for the purpose of identifying non-core assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. While we generally do not dispose of assets solely for the purpose of reducing debt, such dispositions can have the result of furthering our objective of financial flexibility through reduced debt levels. During 2004, 2003 and 2002, our divestitures consisted of the sales of oil and gas properties for net proceeds of $60,000, $330,100 and $354,300, respectively. Our 2004 net proceeds from asset divestitures were primarily derived from the sale of certain oil and gas properties and equipment in Texas and Louisiana. Our 2003 net proceeds from asset divestitures were primarily derived from the sale of our interest in two affiliated entities, Essex I and II Joint Ventures, and certain oil and gas properties in Texas and Louisiana. Our 2002 divestitures were primarily derived from the sale of certain interests in oil and gas properties in Texas, Alabama, Montana, and Louisiana.

Outlook

We completed a significant asset acquisition and a public offering of common stock at the end of 2004. We expect to continue to spend considerable effort in 2005 on acquisitions, as we seek to further our growth. We expect our drilling program to increase from 49 wells (26.910 net) in 2004 to approximately 50 to 55 wells (28 to 31 net) in 2005. Our expected capital program, excluding acquisitions, will be approximately $63 million, approximately 21% greater than the approved 2004 program. Our expected production volumes combined with a strong commodity-pricing environment, that if sustained, is anticipated to produce another year of record cash flow. In order to manage our realized growth in 2004 and our anticipated growth for the next several years, we increased our headcount from 35 employees as of December 31, 2003 to 51 employees as of December 31, 2004 resulting in increased G&A costs for 2004. We expect to add to our staff levels again in 2005 both as a result of past growth and anticipated future growth. To help protect against the possibility of downward commodity price movements, we have entered into several hedges covering approximately 50% of our expected natural gas production and 30% of our expected crude oil production streams for 2005.

Our outlook and the expected results described above are both subject to change based upon factors that include but are not limited to drilling results, commodity prices, access to capital, the acquisitions market and factors referred to in "Forward Looking Statements."

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses, contingent assets and liabilities and the related disclosures in the accompanying financial statements. Changes in these estimates and assumptions could materially affect our financial position, results of operations or cash flows. Management considers an accounting estimate to be critical if:

- it requires assumptions to be made that were uncertain at the time the estimate was made, and
- changes in the estimate or different estimates that could have been selected could have a material impact on our consolidated results of operations or financial condition.

All other significant accounting policies that we employ are presented in the notes to the consolidated financial statements. The following discussion presents information about the nature of our most critical accounting estimates, our assumptions or approach used and the effects of hypothetical changes in the material assumptions used to develop each estimate.

Nature of Critical Estimate Item: Oil & Natural Gas Reserves - Our estimate of proved reserves is based on the quantities of oil and gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in the future years from known reservoirs under existing economic and operating conditions. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs, and workover costs, all of which may in fact vary considerably from actual results. In addition, as prices and cost levels change from year to year, the economics of producing the reserves may change and therefore the estimate of proved reserves also may change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves. Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements.

Assumptions/Approach Used: Units-of-production method to amortize our oil and natural gas properties - The quantity of reserves could significantly impact our depletion expense. Any reduction in proved reserves without a corresponding reduction in capitalized costs will increase the depletion rate.

"Ceiling" Test - The full-cost method of accounting for oil and gas properties requires a quarterly calculation of a limitation on capitalized costs, often referred to as a full-cost ceiling calculation. The ceiling is the discounted present value of our estimated total proved reserves adjusted for taxes and the impact of hedges on pricing, using a 10% discount rate. To the extent that our capitalized costs (net of accumulated depletion and deferred taxes) exceed the ceiling, the excess must be written off to expense. Once incurred, this impairment of oil and gas properties is not reversible at a later date even if oil and gas prices increase. No such impairment was required in the years ended December 31, 2004, 2003, and 2002. This calculation of our proved reserves could significantly impact our ceiling limitation used in determining whether an impairment of our capitalized costs is necessary. The ceiling calculation dictates that prices and costs in effect as of the last day of the period are generally held constant indefinitely. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs, but rather are based on prices and costs in effect as of the end of the period. Oil and natural gas prices used in the reserve valuation at December 31, 2004 were $43.46 per barrel and $6.18 per MMbtu.

Effect if different assumptions used: Units-of-production method to amortize our oil and natural gas properties - A 10% decrease in reserves would have increased our depletion expense for the year by 9%; however, a 10% increase in our reserves would have decreased our depletion expense for the year by 10%.

<u>"Ceiling" limitation test</u> - The most likely factor to contribute to a ceiling test impairment is the price used to calculate the reserve limitation threshold. A significant reduction in the prices at a future measurement date could trigger a full-cost ceiling impairment. At December 31, 2004, we had a cushion (i.e. the excess of the ceiling over our capitalized costs) of $70.0 million. A 10% increase or decrease in prices used would have increased or decreased our cushion by approximately 50%. Our hedging program would serve to mitigate some of the impact of any price decline. Our hedges did not impact the ceiling test in the fourth quarter, and would not have if the price was 10% higher as these prices were within the collars, but had we decreased the price by 10% the price would have been less than our hedge floor and therefore resulted in a decrease in the ceiling of $0.3 million. Another likely factor to contribute to a ceiling test impairment is a revised estimate of reserve volume. A 10% increase or decrease in reserve volume would have increased or decreased our cushion by approximately 35%.

Nature of Critical Estimate Item: <u>Unproved Property Impairment</u> - We have elected to use the full-cost method to account for our oil and gas activities. Investments in unproved properties are not amortized until proved reserves associated with the properties can be determined or until impairment occurs. Unproved properties are evaluated quarterly for impairment on a property-by-property basis. If the results of an assessment indicate that an unproved property is impaired, the amount of impairment is added to the proved oil and natural gas property costs to be amortized.

Assumptions/Approach Used: At December 31, 2004, we had $15.5 million allocated to unproved property. This allocation is based on the estimation by the technical team of whether the property has potential attributable reserves. Therefore, the assessment made by our technical team of the potential reserves will determine whether costs are moved from the unproved category to the full-cost pool for depletion or whether an impairment is taken.

Effect if different assumptions used: A 10% increase or decrease in the unproved property balance (i.e. transfer to full-cost pool) would have increased or decreased our depletion expense by 1% for the year ended December 31, 2004.

Nature of Critical Estimate Item: <u>Asset Retirement Obligations</u> - We have certain obligations to remove tangible equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells. Previously, the costs associated with this activity were capitalized to the full-cost pool and charged to income through depletion. We adopted Statement of Financial Accounting Standards ("SFAS") No. 143, "*Accounting for Asset Retirement Obligations*" effective January 1, 2003, as discussed in Note 2 to our Consolidated Financial Statements. SFAS No. 143 significantly changed the method of accruing for costs an entity is legally obligated to incur related to the retirement of fixed assets ("asset retirement obligations" or "ARO"). Primarily, the new statement requires us to estimate asset retirement costs for all of our assets, inflation adjust those costs to the forecast abandonment date, discount that amount using a credit-adjusted-risk-free rate back to the date we acquired the asset or obligation to retire the asset and record an ARO liability in that amount with a corresponding addition to our asset value. We then accrete the liability quarterly using the period-end effective credit-adjusted-risk-free rate. As new wells are drilled or purchased, their initial asset retirement cost and liability is calculated and recorded. Should either the estimated life or the estimated abandonment costs of a property change upon our quarterly review, a new calculation is performed using the same methodology of taking the abandonment cost and inflating it forward to its abandonment date and then discounting it back to the present using our credit-adjusted-risk-free rate. The carrying value of the asset retirement obligation is adjusted to the newly calculated value, with a corresponding offsetting adjustment to the asset retirement cost (included in the full-cost pool); therefore, abandonment costs will almost always approximate the estimate. When wells are sold the related liability and asset costs are removed from the Balance Sheet.

Assumptions/Approach Used: Estimating the future asset removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Inherent in the estimate of the present value calculation of our AROs are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted-risk-free-rates, timing of settlement, and changes in the legal, egulatory, environmental and political environments.

Effect if different assumptions used: Since there are so many variables in estimating AROs, we attempt to limit the impact of management's judgment on certain of these variables by using input of qualified third parties. We engage an independent engineering firm to evaluate our properties annually. We use the remaining estimated useful life from the year-end reserve reports by our independent reserve engineer in estimating when abandonment could be expected for each property. We utilize a three-year average rate for inflation to diminish any significant volatility that may be present in the short term. We expect to see our calculations impacted significantly if interest rates move from their current lows, as the credit-adjusted-risk-free rate is one of the variables used on a quarterly basis. Our technical team developed a standard cost estimate based on historical costs, industry quotes and depth of wells. Unless we expect a well's plugging to be significantly different than a normal abandonment, we use this estimate. The resulting estimate, after application of a discount factor and some significant calculations, could differ from actual results, despite all our efforts to make an accurate estimate.

Nature of Critical Estimate Item: Income Taxes - In accordance with the accounting for income taxes under SFAS No. 109, *Accounting for Income Taxes,* we have recorded a deferred tax asset and liability to account for the expected future tax benefits and consequences of events that have been recognized in our financial statements and our tax returns. There are several items that result in deferred tax asset and liability impact to the balance sheet, but the largest of which is income taxes and the impact of net operating loss ("NOL") carryforwards. We routinely assess the realizability of our NOL carryforwards that resulted from substantial income tax deductions, prior year losses and acquisitions. We consider future taxable income in making such assessments. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, it is reduced by a valuation allowance.

Assumptions/Approach Used: Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and gas prices). The Company is not currently required to pay any federal income taxes because of NOL carryforwards.

Effect if different assumptions used: We have engaged an independent public accounting firm to assist us in applying the numerous and complicated tax law requirements. However, despite our attempt to make an accurate estimate, the ultimate utilization of our NOL carryforwards is highly dependent upon our actual production and the realization of taxable income in future periods. If we estimate that some or all of our NOL carryforwards are more likely than not going to expire or otherwise not be utilized to reduce future tax, we would record a valuation allowance to remove the benefit of those NOL carryforwards from our financial statements.

Nature of Critical Estimate Item: Derivative & Hedging Activities - Due to the instability of oil and natural gas prices, we may enter into, from time to time, price-risk management transactions (e.g., swaps, collars and floors) for a portion of our oil and natural gas production to achieve a more predictable cash flow, as well as to reduce exposure from commodity price fluctuations. While all of these transactions are economic hedges of price risk, different accounting treatment may apply depending on if they qualify for cash flow hedge accounting. In accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities (as amended),* all transactions are recorded on the balance sheet at fair value. See *ITEMS 1 AND 2. "BUSINESS AND PROPERTIES* – MARKETING."

Hedge Contracts - We formally assess, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used for hedging are expected to be highly effective in offsetting changes in cash flows of the hedged transactions. In the event it is determined that the use of a particular derivative may not be or has ceased to be effective in pursuing a hedging strategy, hedge accounting is discontinued prospectively. The ongoing measurement of effectiveness determines whether the change in fair value is deferred through other comprehensive income ("OCI") on the balance sheet or recorded immediately in revenue on the income statement. The effective portion of the changes in the fair value of hedge contracts is recorded initially in OCI. When the hedged production is sold, the realized gains and losses on the hedge contracts are removed from OCI and recorded in revenue. Ineffective portions of the changes in the fair value of the hedge contracts are recognized in revenue as they occur. While the hedge contract is outstanding, the ineffective gain or loss may increase or decrease until settlement of the contract.

Derivative Contracts - For transactions not accounted for using cash flow hedge accounting, the change in the fair value of the derivative contract is reflected in revenue immediately, i.e. not deferred through OCI, and there is no measurement of effectiveness.

Assumptions/Approach Used: Estimating the fair values of derivative instruments requires complex calculations, including the use of a discounted cash flow technique, estimates of risk and volatility, and subjective judgment in selecting an appropriate discount rate. In addition, the calculations use future market commodity prices, which although posted for trading purposes, are merely the market consensus of forecasted price trends. The results of the fair value calculations cannot be expected to represent exactly the fair value of our commodity hedges. We currently obtain the fair value of our positions from our counterparties. Our practice of relying on our counterparties who are more specialized and knowledgeable in preparing these complex calculations reduces our management's input.

Effect if different assumptions used: At December 31, 2004, a 10% change in the commodity price per unit, as long as the price is either above the ceiling or below the floor price, would cause the fair value total of our derivative financial instrument to increase or decrease by approximately $234,200.

RESULTS OF OPERATIONS

This section includes discussion of our 2004, 2003 and 2002 results of operations. We are an independent energy company engaged in the exploration, development, acquisition and production of oil and natural gas. Our resources and assets are managed and our results reported as one operating segment. We conduct our operations primarily along the onshore United States, Gulf Coast, with our primary emphasis in south Texas, Louisiana and southeastern New Mexico.

Year Ended December 31, 2004 Compared to the Year Ended December 31, 2003

Revenue and Production

Total revenue increased 90% from 2003 to 2004. For the years ended December 31, 2004 and 2003, our product mix contributed the following percentages of production and revenues:

	REVENUES [1]		PRODUCTION	
	2004	2003	2004	2003
Natural gas (Mcf)	82%	82%	75%	78%
Natural gas liquids (Bbls)	7%	7%	14%	13%
Crude oil (Bbl)	11%	11%	11%	9%
Total (Mcfe)	100%	100%	100%	100%

[1] Includes effect of hedging and derivative transactions.

The following table summarizes production volumes, average sales prices and operating revenue for our oil and natural gas operations for the years ended December 31, 2004 and 2003.

	December 31,		2004 Period Compared to 2003 Period	
	2004	2003 (1)	$ Increase (Decrease)	% Increase (Decrease)
Production Volumes:				
Natural gas (Mcf)	9,148,191	6,290,055	2,858,136	45%
Natural gas liquids (Bbls)	276,184	177,892	98,292	55%
Oil and condensate (Bbls)	214,622	122,592	92,030	75%
Natural gas equivalent (Mcfe)	12,093,027	8,092,961	4,000,066	49%
Average Sales Price:				
Natural gas ($ per Mcf)(1)	$ 5.91	$ 5.14	$ 0.77	15%
Natural gas liquids ($ per Bbl)	$ 15.83	$ 12.37	$ 3.46	28%
Oil and condensate ($ per Bbl)(1)	$ 39.77	$ 31.48	$ 8.29	26%
Natural gas equivalent ($ per Mcfe) (2)	$ 5.33	$ 4.19	$ 1.14	27%
Operating Revenue:				
Natural gas (1)	$ 54,056,944	$ 32,322,043	$ 21,734,901	67%
Natural gas liquids	4,373,245	2,200,350	2,172,895	99%
Oil and condensate(1)	8,535,222	3,859,204	4,676,018	121%
Loss on hedging and derivatives	(2,460,063)	(4,455,590)	1,995,527	45%
Total (2)	$ 64,505,348	$ 33,926,007	$ 30,579,341	90%

(1) Excludes the effect of hedging and derivative transactions.

(2) Includes the effect of hedging and derivative transactions.

Our revenue is sensitive to changes in prices received for our products. A substantial portion of our production is sold at prevailing market prices, which fluctuate in response to many factors that are outside of our control. Imbalances in the supply and demand for oil and natural gas can have a dramatic effect on the prices we receive for our production. Political instability, availability of alternative fuels, the economy, weather and other factors outside of our control could impact supply and demand. Several of these factors, including instability in the Middle East, lower inventories and a cold winter contributed to commodity price increases in 2004.

Natural gas revenue, excluding hedging activity, increased 67% for the year ended December 31, 2004 over the same period in 2003 due to significantly higher production and higher realized prices. Average natural gas production increased 45% from 17.2 MMcf/D in 2003 to 25.0 MMcf/D in 2004 due to production from new wells drilled, primarily in our Gato Creek and Encinitas locations, and those acquired at the end of 2003, including the Miller and south Texas properties. Partially offsetting the increases in production were natural declines at our O'Connor Ranch and O'Connor Ranch East properties, as well as declines due to increased salt-water production on the Thibodeaux well. The overall increase in production compared to the prior year period resulted in an increase in revenue of approximately $14.7 million (based on 2003 comparable period pre-hedge prices). Excluding the effect of hedges, the average natural gas sales price for production in 2004 was $5.91 per Mcf compared to $5.14 per Mcf for 2003. This increase in average price received resulted in increased revenue of approximately $7.0 million (based on current year production).

Revenue from the sale of NGLs increased 99% for the year ended December 31, 2004 over the same period in 2003. Production volumes for NGLs increased 55%, from 487 Bbls/D for 2003 to 755 Bbls/D for 2004 due primarily to increased production from new wells drilled at Gato Creek, Encinitas, Santellana, and Southeast New Mexico, those acquired at year-end 2003 from Miller and in south Texas, and new processing and treating agreements entered into during 2004. Our production at Gato Creek receives a lower average price on NGL's (approximately $1.20 per barrel) due to the terms of our marketing agreement for that area. In 2003, the majority of our NGL production came from Gato Creek, whereas in 2004 we have added more market priced production that has increased our overall price realized. The increase in NGL production increased revenue by approximately $1.2 million (based on 2003 comparable period average prices). Higher average realized prices for the year ended December 31, 2004 resulted in an ncrease in revenue of approximately $1.0 million (based on current year production). The average realized price for NGLs for the year ended December 31, 2004 was $15.83 per barrel compared to $12.37 per barrel for the same period in 2003.

Revenue from the sale of oil and condensate, excluding derivative activity, increased 121% for the year ended December 31, 2004 as compared to the comparable prior year period in 2003 due to increased production and realized prices. Production volumes for oil and condensate increased 75% to 586 Bbls/D for the year ended December 31, 2004 compared to 336 Bbls/D for the same prior year period due primarily to production from the properties acquired from Miller and in south Texas, as well as new wells drilled during 2004 at our Encinitas, Gato Creek and Southeast New Mexico properties. The increase in oil and condensate production resulted in an increase in revenue of approximately $2.9 million (based on 2003 comparable period average prices). The average realized price for oil and condensate before the derivative losses for the year ended December 31, 2004 was $39.77 per barrel compared to $31.48 per barrel in the same period of 2003. These higher average prices for 2004 resulted in an increase in revenue of approximately $1.8 million (based on current year production).

Losses on hedging and derivatives decreased 45% for the year ended December 31, 2004 over the same period in 2003 due to better alignment of hedge and derivative contracts with market pricing. The volume and price contract terms vary from period to period and therefore interact differently with the market prices. While we are unable to predict the market prices, we enter into contracts that we expect will protect us in the event of significant downturns in the market. Oil and condensate revenues were decreased by realized and unrealized losses on our oil derivatives. For the year ended December 31, 2004 we recorded $880,765 of realized losses on oil derivatives settlements and $564,548 of unrealized losses representing the change in the mark-to-market fair value of our outstanding oil derivative contracts. We did not apply hedge accounting to these transactions. See Note 9 to our consolidated financial statements. These losses account for a $6.74 per barrel decrease in the overall realized oil price for the year ended December 31, 2004 from $39.77 per barrel to $33.03 per barrel. There was no oil derivative activity during 2003. Should crude oil prices decrease from the current levels, we would realize lower revenues from sales of crude oil, but our oil derivative losses would also decrease and could possibly result in a gain position. The actual pricing will also impact our cash outlay as these transactions settle throughout the year. For the year ended December 31, 2004, we recognized the $686,250 premium paid for a natural gas hedge entered into in 2003 and $328,500 representing realized losses from natural gas hedging contract settlements. These losses decreased the effective natural gas sales price by $0.11 per Mcf. Included within revenue for the year ended December 31, 2003 was $4.5 million representing realized losses from natural gas hedging contract settlements. These losses decreased the effective natural gas sales price by $0.71 per Mcf for 2003. Should natural gas prices decrease from the current high levels, this could materially affect our revenues that are not hedged.

Costs and Operating Expenses

The table below presents a detail of our 2004 and 2003 expenses:

	December 31,		2004 Period Compared to 2003 Period	
	2004	2003	$ Increase (Decrease)	% Increase (Decrease)
Lease operating expenses	$ 4,945,918	$ 2,676,050	$ 2,269,868	85%
Severance and ad valorem taxes	4,362,852	2,439,744	1,923,108	79%
Depreciation, depletion, amortization and accretion:				
Oil and gas property and equipment	21,471,606	12,906,956	8,564,650	66%
Other assets	357,300	603,698	(246,398)	(41)%
ARO accretion	98,968	66,625	32,343	49%
General and administrative:				
Deferred compensation – repriced options	1,135,628	1,219,349	(83,721)	(7)%
Deferred compensation – restricted stock	498,372	372,151	126,221	34%
Other general and administrative	7,812,970	5,540,140	2,272,830	41%
	40,683,614	25,824,713	14,858,901	58%
Other expense, net	437,459	662,287	(224,828)	(34)%
Total	$ 41,121,073	$ 26,487,000	$ 14,634,073	55%

Lease operating expenses for the year ended December 31, 2004 totaled $4.9 million compared to $2.7 million in the same period of 2003, an increase of 85%. Current year results were impacted by the addition of the Miller and south Texas properties (acquisitions late in 2003) and the drilling of 40 successful wells during 2004. Operating expenses averaged $0.41 per Mcfe for the year ended December 31, 2004 compared to $0.33 per Mcfe for the prior year period.

Severance and ad valorem taxes for the year ended December 31, 2004 increased 79% over 2003. Severance tax expense for 2003 was 97% higher than the prior year period as a result of higher revenue. Severance taxes are levied directly off of our revenue dollar, so the increase is consistent with the 90% increase in revenue. The rate realized for the year also increased as a result of the changing mix of our production locations. We had a significant portion of production in other states such as Louisiana in 2003 as compared to the increase in production in Texas in 2004, which imposes a tax rate of approximately 7.5% of the revenue dollar. For the year ended December 31, 2004, severance tax expense was approximately 6.0% of total revenue compared to 5.3% of total revenue for the comparable 2003 period. Ad valorem costs decreased 5% since 2003 as a result of adjustments to expense estimates accrued in 2003. On an equivalent basis, severance and ad valorem taxes averaged $0.36 per Mcfe and $0.30 per Mcfe for the years ended December 31, 2004 and 2003, respectively.

DD&A and accretion expense for the year ended December 31, 2004 increased 62% over the year ended December 31, 2003. Full cost depletion on our oil and natural gas properties totaled $21.5 million for 2004 compared to $12.9 million in 2003 due to both increases in production and the depletion rate. For the year ended December 31, 2004, higher oil and natural gas production compared to the prior year period resulted in an increase in depletion expense of $6.4 million. Depletion expense on a unit of production basis for the year ended December 31, 2004 was $1.78 per Mcfe, 12% higher than the 2003 rate of $1.59 per Mcfe. The higher depletion rate per Mcfe resulted in an increase in depletion expense of $2.2 million. The increase in the depletion rate was primarily due to a higher amortizable base in 2004 compared to the prior year without a corresponding increase in reserves. Depreciation of other assets decreased 41% since 2003 due to accelerating depreciation on leasehold improvements and computer equipment in 2003. When we moved to a new office building early in 2003, we fully depreciated certain assets that would no longer be in service in the new location. Many older assets became fully depreciated at that time and were not replaced in 2004. Accretion expense on our ARO liability has increased 49% for the addition of new obligations associated with wells added during 2004, as well as the fact that accretion is calculated using the interest method of allocation, which calculates interest on the cumulative balance such that the interest increases with each subsequent period.

Total general and administrative ("G&A") expenses for the year ended December 31, 2004 were $9.4 million, an increase of 32% compared to the prior year total of $7.1 million. Total G&A costs include deferred compensation related to repriced options, deferred compensation related to restricted stock grants and other G&A costs.

Deferred compensation expense consists of costs reported in accordance with FIN 44 and amortization related to restricted stock awards. FIN 44 requires variable accounting for stock options with terms modified after issuance (see Note 2 to our consolidated financial statements). Variable accounting provides for a non-cash charge to compensation expense if the price of our common stock on the last trading day of a reporting period is greater than the exercise price of certain re-priced options. FIN 44 could also result in a credit to compensation expense to the extent that the trading price declines from the trading price as of the end of the prior period, but not below the exercise price of the options. We adjust deferred compensation expense upward or downward on a monthly basis based on the trading price at the end of each such period. We are required to report under this rule as a result of non-qualified stock options granted to employees and directors in prior years and re-priced in May of 1999, as well as certain newly issued options in conjunction with the re-pricing. A FIN 44 charge on our re-priced stock options was required in both 2004 and 2003 as a result of our stock price exceeding the exercise price of those re-priced options. The increase in deferred compensation for restricted stock awards is related to the increase in employee headcount during 2004.

Other G&A expenses for the year ended December 31, 2004, which does not include the deferred compensation expenses discussed above increased 41% since 2003. The increase in other G&A was in part attributable to the growth in our company from 35 employees at December 31, 2003 to 51 employees at December 31, 2004. We were also impacted by higher audit and legal fees and amounts spent on investor relations projects during 2004. We incurred approximately $390,400 of costs for the implementation of the Sarbanes-Oxley 404 Internal Control Report during 2004. This does not include any amounts of the significant internal resources that were directed towards this project. These increases were partially offset by decreases in general office related spending in 2004. Included in 2003 was a $70,000 settlement for a lawsuit related to seismic rights. For the years ended December 31, 2004 and 2003, overhead reimbursement fees reduced G&A costs by approximately $262,000 and $120,500, respectively. The Company capitalized $2.2 million and $1.7 million of general and administrative costs in 2004 and 2003, respectively. Other G&A expenses on a unit of production basis for the year ended December 31, 2004 was $0.65 per Mcfe compared to $0.68 per Mcfe for the comparable 2003 period.

Included in other income (expense) was interest expense, net of amounts capitalized, of $331,399 for the year ended December 31, 2004 compared to $678,805 in the same 2003 period. Interest expense, including facility fees, was $1.0 million for 2004 on weighted average debt of $20.0 million compared to interest expense of $923,308 on weighted average debt of approximately $23.0 million for 2003. Capitalized interest for the year ended December 31, 2004 totaled $701,654 compared to $244,503 in the prior year. At December 31, 2004, our unproved property balance was $15.5 million compared to $5.0 million at December 31, 2003, resulting in the lower capitalized interest for 2003. Also included in other income (expense) for the year ended December 31, 2004 was $142,135 representing amortization of deferred loan costs associated with our credit facility.

Interest income totaled $36,075 for the year ended December 31, 2004 compared to $16,518 for the same period in 2003. The increase in interest income is due primarily to the overall increase in funds that were invested in overnight money market funds, especially in December in the period between receipt of offering proceeds and closing the Contango Asset Acquisition.

An income tax provision was recorded for the year ended December 31, 2004 of $8.3 million. For the year ended December 31, 2003, an income tax provision of $2.7 million was recorded. Due to changes in amounts of permanent tax differences, including meals and entertainment and compensation expense, our effective tax rate changed from 36.7% in 2003 to 35.3% in 2004. As of December 31, 2004, approximately $73.9 million of net operating loss carryforwards have been accumulated or acquired that will begin to expire in 2007. Currently, we do not anticipate making federal tax payments in 2005.

Upon adoption of SFAS No. 143 on January 1, 2003, we recorded a cumulative effect of a change in accounting principal of $357,825 (net of income taxes of $192,675) and accretion expense, to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depletion and accretion.

For the year ended December 31, 2004, we had net income of $15.1 million, or $1.16 basic earnings per share and $1.11 diluted earnings per share, as compared to net income of $4.4 million, or $0.45 basic and $0.44 diluted earnings per share in 2003. Basic weighted average shares outstanding increased from approximately 9.7 million for the year ended December 31, 2003 to 13.0 million in the comparable 2004 period. The impact of the shares issued in the Miller transaction was not fully realized until 2004 since the merger closed and the shares were issued in December 2003. The same is true in 2004 for the shares issued in the public offering in December 2004. There were also increases due to options exercised and vesting of restricted stock during 2004.

Year Ended December 31, 2003 Compared to the Year Ended December 31, 2002

Revenue and Production

Total revenue increased 62% from 2002 to 2003. For the years ended December 31, 2003 and 2002, our product mix contributed the following percentages of production and revenues:

	REVENUES [1]		PRODUCTION	
	2003	2002	2003	2002
Natural Gas (Mcf)	82%	79%	78%	76%
Natural gas liquids (Bbls)	7%	8%	13%	14%
Crude oil (Bbl)	11%	13%	9%	10%
Total (Mcfe)	100%	100%	100%	100%

[1] Includes effect of hedging and derivative transactions.

The following table summarizes production volumes, average sales prices and operating revenue for our oil and natural gas operations for the years ended December 31, 2003 and 2002.

	December 31,		2003 Period Compared to 2002 Period	
	2003	2002(1)	$ Increase (Decrease)	% Increase (Decrease)
Production Volumes:				
Natural gas (Mcf)	6,290,055	5,266,390	1,023,665	19%
Natural gas liquids (Bbls)	177,892	161,301	16,591	10%
Oil and condensate (Bbls)	122,592	119,527	3,065	3%
Natural gas equivalent (Mcfe)	8,092,961	6,951,357	1,141,604	16%
Average Sales Price:				
Natural gas ($ per Mcf)(3)	$ 5.14	$ 3.20	$ 1.94	61%
Natural gas liquids ($ per Bbl)	$ 12.37	$ 10.31	$ 2.06	20%
Oil and condensate ($ per Bbl)(3)	$ 31.48	$ 22.88	$ 8.60	38%
Natural gas equivalent ($ per Mcfe) (2)	$ 4.19	$ 3.01	$ 1.18	39%
Operating Revenue:				
Natural gas (3)	$ 32,322,043	$ 16,840,046	$ 15,481,997	92%
Natural gas liquids	2,200,350	1,663,707	536,643	32%
Oil and condensate(3)	3,859,204	2,734,491	1,124,713	41%
Loss on hedging and derivatives	(4,455,590)	(326,950)	(4,128,640)	1263%
Total	$ 33,926,007	$ 20,911,294	$ 13,014,713	62%

(1) Results for 2002 were favorably impacted by the recognition in the second quarter of 2002 of revenue associated with underaccruals in prior periods. This adjustment resulted in 142 MMcfe of additional production and $577,200 of additional revenue.
(2) Includes the effect of hedging and derivative transactions.
(3) Excludes the effect of hedging and derivative transactions.

Natural gas revenue, excluding hedging activity, increased 92% from $16.8 million for the year ended December 31, 2002 to $32.3 million for 2003 due to significantly higher average realized prices coupled with an increase in production, partially offset by a higher realized hedge loss. Excluding the effect of hedges, the average natural gas sales price for production in 2003 was $5.14 per Mcf compared to $3.20 per Mcf for 2002. This increase in average price received resulted in increased revenue of approximately $12.2 million (based on 2003 production). For the year ended December 31, 2003, average natural gas production increased 19% from 14.4 MMcf/d in 2002 to 17.2 MMcf/d in 2003 due to production from new wells drilled and acquired, primarily our O'Connor Ranch East, Gato Creek and Encinitas properties, partially offset by natural declines at our Austin Field and O'Connor Ranch properties. This increase in production compared to the prior year resulted in an increase in revenue of approximately $3.3 million (based on 2002 comparable period prices).

Revenue from the sale of oil and condensate totaled $3.9 million for the year ended December 31, 2003, an increase of 41% from the prior year total of $2.7 million. The average realized price for oil and condensate for the year ended December 31, 2003 was $31.48 per barrel compared to $22.88 per barrel in 2002. Higher average prices for the year 2003 resulted in an increase in revenue of approximately $1.1 million (based on 2003 production). Production volumes for oil and condensate increased 3% to 336 Bbls/d for the year ended December 31, 2003 compared to 327 Bbls/d for the same prior year period. The increase in oil and condensate production resulted in an increase in revenue of approximately $70,100 (based on 2002 comp arable period average prices).

Revenue from the sale of NGLs totaled $2.2 million for the year ended December 31, 2003, an increase of 32% from the 2002 total of $1.7 million. Higher average realized prices for the year ended December 31, 2003 resulted in an increase in revenue of $365,500 (based on 2003 production). The average realized price for NGLs for the year ended December 31, 2003 was $12.37 per barrel compared to $10.31 per barrel for the same period in 2002. Production volumes for NGLs increased 10%, from 442 Bbls/d for the year ended December 31, 2002 to 487 Bbls/d for the year ended December 31, 2003 due primarily to new production from the Thibodeaux well. The increase in NGL production increased revenue by $171,100 (based on 2002 comparable period average prices).

Losses on hedging and derivatives increased significantly for the year ended December 31, 2003 over the same period in 2002 due to the unexpected movement of prices in the market. Included within natural gas revenue for the year ended December 31, 2003 and 2002 was $4.5 million and $0.3 million, respectively, representing cash settlement losses from natural gas hedging activity. Including the effect of our hedges, our average natural gas sales price for production in 2003 was $4.43 per Mcf compared to $3.14 per Mcf for 2002. These losses decreased the effective natural gas sales price by $0.71 per Mcf and $0.06 per Mcf, for the years ended December 31, 2003 and 2002, respectively.

Costs and Operating Expenses

The table below presents a detail of our 2003 and 2002 expenses:

	December 31,		2003 Period Compared to 2002 Period	
	2003	2002	$ Increase (Decrease)	% Increase (Decrease)
Lease operating costs	$ 2,676,050	$ 2,208,892	$ 467,158	21%
Severance and ad valorem taxes	2,439,744	1,622,698	817,046	50%
Depreciation, depletion, and amortization:				
Oil and gas property and equipment	12,906,956	9,697,144	3,209,812	33%
Other assets	603,698	729,523	(125,825)	(17)%
ARO accretion	66,625	--	66,625	*
General and administrative:				
Deferred compensation – repriced options	1,219,349	3,385	1,215,964	*
Deferred compensation – restricted stock	372,151	399,249	(27,098)	(7)%
Other general and administrative	5,540,140	4,826,793	713,347	15%
	25,824,713	19,487,684	6,337,029	33%
Other expense, net	662,287	200,805	461,482	230%
Total	$ 26,487,000	$ 19,688,489	$ 6,798,511	35%

* Not meaningful

Lease operating expenses for the year ended December 31, 2003 increased 21% compared to the same period of 2002 due to additional costs for 36 new wells drilled during the year and wells acquired late in 2003 and increased salt water disposal costs on the Thibodeaux well. Average operating expenses for the year ended December 31, 2003 were $0.33 per Mcfe as compared to $0.32 per Mcfe for the prior year period.

Severance and ad valorem taxes for the year ended December 31, 2003 increased 50% from 2002. Severance tax expense for 2003 was 67% higher than the prior year period as a result of higher revenue. For the year ended December 31, 2003, severance tax expense was approximately 5.3% of total revenue compared to 5.7% of total revenue for the comparable 2002 period. Ad valorem costs increased 3% from $419,400 in 2002 to $433,300 in 2003 due primarily to the addition of the Miller and south Texas properties acquired late in 2003. On an equivalent basis, severance and ad valorem taxes averaged $0.30 per Mcfe and $0.23 per Mcfe for the years ended December 31, 2003 and 2002, respectively.

DD&A and accretion for the year ended December 31, 2003 totaled $13.6 million compared to $10.4 million for the year ended December 31, 2002. Full cost depletion on our oil and natural gas properties totaled $12.9 million for 2003 compared to $9.7 million in 2002. Depletion expense on a unit of production basis for the year ended December 31, 2003 was $1.59 per Mcfe, 14% higher than the 2002 rate of $1.39 per Mcfe. The higher depletion rate per Mcfe resulted in an increase in depletion expense of $1.6 million. For the year ended December 31, 2003, higher oil and natural gas production compared to the prior year period resulted in an increase in depletion expense of $1.6 million. The increase in the depletion rate was primarily due to a higher amortizable base in 2003 compared to the prior year without a corresponding increase in reserves. Depreciation of furniture and fixtures totaled $603,698, a decrease of 17% compared to the prior year total of $729,523 as a result of certain assets related to the previous office building becoming fully depreciated. We adopted SFAS No. 143, effective January 1, 2003, and as a result, we recorded accretion expense associated with our asset retirement obligation of $66,625 for the year ended December 31, 2003 compared to zero in 2002 due the change in accounting for asset retirement obligations (see Note 7 to our consolidated financial statements).

Total general and administrative ("G&A") expenses for the year ended December 31, 2003 was $7.1 million, an increase of 36% compared to the prior year total of $5.2 million. Total G&A costs include deferred compensation related to repriced options, deferred compensation related to restricted stock grants and other G&A costs.

Deferred compensation expense consists of costs reported in accordance with FIN 44 and amortization related to restricted stock awards. A FIN 44 charge of $1.2 million was incurred for the year ended December 31, 2003 compared to a charge of $3,385 in the comparable prior year period as a result of the variable accounting for the interaction of the rising stock price and the exercise price of certain re-priced options.

Amortization related to restricted stock awards granted over the past two years totaled $372,151 and $399,249 for the years ended December 31, 2003 and 2002, respectively.

Other G&A expenses for the year ended December 31, 2003, which does not include the deferred compensation expenses discussed above, totaled $5.5 million, a 15% increase from the 2002 total of $4.8 million. The increase in other G&A was attributable to higher audit and legal fees, higher franchise taxes, office moving costs and the settlement of a lawsuit related to seismic rights in April 2003 for $70,000. In addition, we incurred costs associated with the Miller merger of approximately $279,400 (including retention, salaries and benefits, and integration costs) and software implementation costs to integrate our production and land computer systems with accounting of $88,300. These costs were partially offset by lower rent and parking and lower reserve engineering fees compared to the prior year periods. For the years ended December 31, 2003 and 2002, overhead reimbursement fees reduced G&A costs by approximately $120,500 and $208,200, respectively. The Company capitalized $1.7 million and $1.5 million of general and administrative costs in 2003 and 2002, respectively. Other G&A expenses on a unit-of-production basis for the year ended December 31, 2003 was $0.68 per Mcfe compared to $0.69 per Mcfe for the comparable 2002 period.

Included in other income (expense) was interest expense of $678,800 for the year ended December 31, 2003 compared to $227,800 in the same 2002 period. Interest expense, including facility fees, was $923,300 for 2003 on weighted average debt of $23.0 million compared to interest expense of $766,700 on weighted average debt of approximately $15.4 million for 2002. Capitalized interest for the year ended December 31, 2003 totaled $244,500 compared to $623,400 in the prior year. At December 31, 2003, our unproved property balance was $5.0 million compared to $7.9 million at December 31, 2002, resulting in the lower capitalized interest for 2003. Also included in interest expense for the year ended December 31, 2002 was $84,500 representing amortization of deferred loan costs associated with our credit facility, which was fully amortized by 2003.

Interest income totaled $16,500 for the year ended December 31, 2003 compared to $27,000 for the same period in 2002. The decrease in interest income is due primarily to the overall decrease in the floating interest rates at which the funds were invested in overnight money market funds.

An income tax provision was recorded for the year ended December 31, 2003 of $2.7 million as compared to $473,100 for the year ended December 31, 2002. Due to changes in permanent differences, including meals and entertainment and compensation expense, our effective tax rate changed from 38.7% in 2002 to 36.7% in 2003. As of December 31, 2003, approximately $50.1 million of net operating loss carryforwards had been accumulated or acquired.

Upon adoption of SFAS No. 143 on January 1, 2003, we recorded a cumulative effect of a change in accounting principal of $357,800 (net of income taxes of $192,700) and accretion expense, to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depletion and accretion.

For the year ended December 31, 2003, we had net income of $4.4 million, or $0.45 basic earnings per share and $0.44 diluted earnings per share, as compared to net income of $749,700, or $0.08 basic and diluted earnings per share in 2002. Basic weighted average shares outstanding increased from approximately 9.4 million for the year ended December 31, 2002 to 9.7 million in the comparable 2003 period. The increase was due primarily to options exercised and vesting of restricted stock during 2003. The impact of the shares issued in December 2003 for the Miller transaction was not fully realized until 2004 since the merger closing and share issuance occurred late in 2003.

Liquidity and Capital Resources

Our primary ongoing source of capital is the cash flow generated from our operating activities supplemented by borrowings under our credit facility. Net cash generated from operating activities is a function of production volumes, commodity prices, which are inherently volatile and unpredictable, operating efficiency and capital spending. Our business, as with other extractive industries, is a depleting one in which each gas equivalent unit produced must be replaced or we, and a critical source of our future liquidity, will shrink. Our overall production decline is approximately 17% per year as we look to the future. Less predictable than production declines from our proved reserves is the impact of constantly changing oil and natural gas prices on cash flows and, therefore capital budgets. We attempt to mitigate the price risk with our hedging program. Reserves and production volumes are influenced, in part, by the amount of future capital expenditures. In turn, capital expenditures are influenced by many factors including drilling results, oil and gas prices, industry conditions, prices, availability of goods and services and the extent to which oil and gas properties are acquired.

For 2004, a significant source of cash was the net proceeds of $47,810,000 that we received, before direct costs of $0.5 million, from our December 2004 offering of 3,500,000 shares of our common stock. In January 2005, the underwriters exercised their over-allotment option for 525,000 additional shares of our common stock resulting in an additional $7.2 million of net proceeds to us. As of March 15, 2005, we have approximately $91.8 million available under this current shelf registration statement.

Our primary needs for cash are for exploration, development and acquisition of oil and gas properties, and the repayment of principal and interest on outstanding debt. We attempt to fund our exploration and development activities primarily through internally generated cash flows and budget capital expenditures based on projected cash flows. We routinely adjust capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, and cash flow. We typically have funded acquisitions from borrowings under our credit facility and cash flow from operations. We have historically utilized net cash provided by operating activities, debt and equity as capital resources to obtain necessary funding for all of our cash needs.

Some significant changes to working capital may also affect our liquidity in the short term. The increase in accrued fees for professional services and royalties payable at December 31, 2004 accounts for most of the increase in accrued liabilities. Therefore, we expect our short-term cash outflows for the first quarter to increase as these liabilities come due.

The fair value of our outstanding hedge and derivative contracts is reflected on the balance sheet, and we show an asset and a liability for the separate positions with each of our two counterparties. Our asset position at December 31, 2004 is larger than it was at December 31, 2003 contributing to the working capital increase, slightly offset by the liability position that is included in the December 31, 2004 balance sheet. The hedge and derivative financial instrument liability represents the amount by which future strip commodity prices exceed the price caps on our contracts at the balance sheet date. The hedge and derivative financial instrument asset represents the amount by which strip commodity prices are lower than the price floors on our contracts at the balance sheet date. Should commodity prices increase or decrease, the applicable positions would change accordingly and the unrealized losses that are reflected in revenue and the unrealized gains reflected in other comprehensive income could possibly reduce or result in gains or losses, respectively. When hedges and derivatives require cash settlement, the Company is receiving higher cash inflows on the sale of production at higher prices, therefore the use of those funds would adequately cover any derivative and hedge payments when they come due.

We have historically used our credit facility to supplement any deficiencies between operating cash flow and capital expenditures. We had $20.0 million outstanding under the credit facility at December 31, 2004, which was subsequently reduced in January 2005 to $13.0 million with proceeds from the underwriter's over-allotment option to our December 2004 public stock offering (see discussion below) and further to $10.0 million from cash on hand in February. The maturity for this credit facility is December 31, 2006.

After considering the impact of these working capital changes and our forecasts of future results of operations, we believe that cash flows from operating activities, as supplemented by borrowings on our credit facility, combined with our ability to control the timing of the majority of our future exploration and development requirements will provide us with the flexibility and liquidity to meet our planned capital requirements for 2005. In addition, our credit facility had $45.0 million available at December 31, 2004 ($52.0 million after net proceeds from the underwriter over-allotment option exercise in January 2005 were used to repay debt) for general corporate purposes, exploratory and developmental drilling and acquisitions of oil and gas properties.

During 2004, the rise in our stock price contributed to significant exercises of warrants and stock options, from which we have realized increased cash flows from financing activities. On March 2, 2004, Mr. Elias, our Chairman and Chief Executive Officer, exercised outstanding warrants for 45,000 shares of common stock, which resulted in proceeds to us of approximately $240,750. Increased activity in stock option exercises has also resulted in proceeds to us of approximately $2.0 million for the year ended December 31, 2004. We typically do not rely on proceeds from the exercise of warrants and stock options to sustain our business as they are unpredictable events.

We had cash and cash equivalents at December 31, 2004 of $2.3 million consisting primarily of short-term money market investments, as compared to $1.3 million at December 31, 2003. Working capital was $9.0 million as of December 31, 2004, as compared to $0.9 million at December 31, 2003.

Net Cash Provided By Operating Activities

Cash flows provided by operating activities were $42.3 million, $23.9 million and $10.4 million, for the years ended December 31, 2004, 2003, and 2002, respectively. The significant increase in cash flows provided by operating activities for the year ended December 31, 2004 compared to 2003 was primarily due to higher total revenues partially offset by higher operating expense. Revenue for 2004 increased 90% over 2003. The increase in cash flows provided by operating activities in 2003 as compared to 2002 was due primarily to higher oil and gas revenue partially offset by higher operating expense.

Net cash generated from operating activities is a function of commodity prices, which are inherently volatile and unpredictable, production and capital spending. Our business, as with other extractive industries, is a depleting one in which each gas equivalent produced must be replaced or we, and a critical source of our future liquidity, will shrink. Our ability to prevent shrinkage will be affected in the future by the successes and/or failures of our exploration, production and acquisition activities. Less predictable than production declines from our proved reserves is the impact of constantly changing oil and natural gas prices on cash flows and, therefore capital budgets.

For these reasons, we only forecast, for internal use by management, an annual cash flow. We do analyze contingent well opportunities that may extend further than one year, but do not rely on them for sustaining our business. These annual forecasts are revised monthly and capital budgets are reviewed by management and adjusted as warranted by market conditions. Longer-term cash flow and capital spending projections are neither developed nor used by management to operate our business.

In the event such capital resources are not available to us, our drilling and other activities may be curtailed. See *ITEMS 1 AND 2. "BUSINESS AND PROPERTIES* – RISK FACTORS – Our operations have significant capital requirements."

Net Cash Used In Investing Activities

We reinvest a substantial portion of our cash flows in our drilling, acquisition, land and geophysical activities. As a result, we used $89.4 million in investing activities during 2004. Capital expenditures for the year ended December 31, 2004 were partially offset by $60,000 of proceeds from the sale of one well and a gas cooler during the year. Capital expenditures of $45.7 million were attributable to the drilling of 49 gross wells, 40 of which were successful. Acquisition costs totaled $40.0 million for the year ended December 31, 2004, which includes $39.8 million related to the Contango Asset Acquisition. Other spending includes $2.6 million in expenditures attributable to land holdings and $0.6 million for increased seismic data and other geological and geophysical expenditures. The remaining capital expenditures were associated with computer hardware, office furniture and equipment for the expansion into additional office space.

During the year ended December 31, 2003, we used $28.1 million in investing activities. Capital expenditures of $33.6 million for the year ended December 31, 2003, were partially offset by $5.2 million of cash received in the Miller merger net of merger costs incurred and $0.3 million in proceeds from the sale of oil and gas properties during 2003. Capital expenditures of $18.3 million were attributable to the drilling of 36 gross wells, 28 of which were successful. Acquisition costs, excluding Miller, totaled $12.3 million for the year ended December 31, 2003, and an additional $0.8 million in expenditures was attributable to land holdings, including seismic data and other geological and geophysical expenditures. The remaining capital expenditures were associated with computer hardware and office equipment.

During the year ended December 31, 2002, we used $19.3 million in investing activities. Capital expenditures of $19.6 million for the year ended December 31, 2002, were partially offset by $0.4 million in proceeds from the sale of oil and gas properties during 2003. Capital expenditures of $12.7 million were attributable to the drilling of 13 gross wells, 11 of which were successful. Acquisition costs totaled $1.4 million for the year ended December 31, 2002, and an additional $5.5 million in expenditures was attributable to land holdings, including $1.0 million for increased seismic data and other geological and geophysical expenditures. The remaining capital expenditures were associated with computer hardware and office equipment.

Due to our active exploration, development and acquisition activities, we have experienced and expect to continue to experience substantial working capital requirements. We currently anticipate capital expenditures in 2005 to be approximately $63 million. Approximately $51.7 million is allocated to our expected drilling and production activities; $7.9 million is allocated to land and seismic activities; and $3.3 million relates to capitalized interest, G&A and other. We intend to fund these capital expenditures, and other commitments and working capital requirements with expected cash flow from operations and, to the extent necessary, other financing activities. Should there be a change in our pricing or production assumptions, we believe that we have sufficient financial flexibility from other financing activities to meet our financial obligations as they come due, and we would recommend to our Board an adjustment to our capital expenditures program accordingly so as to avoid unnecessary incremental borrowings that may be needed for acquisitions. We do not explicitly budget for acquisitions; however, we do expect to spend considerable effort evaluating acquisition opportunities. We expect to fund acquisitions through traditional reserve-based bank debt and/or the issuance of equity and, if required, through additional debt and equity financings.

Net Cash Provided By Financing Activities

Cash flows provided by financing activities totaled $48.1 million for the year ended December 31, 2004. We had $27.0 million in borrowings and $28.0 million in repayments under our credit facility. We incurred loan costs of approximately $0.4 million in establishing our new credit facility. In addition, we received $2.3 million in proceeds from the issuance of common stock related to options and warrants exercised in 2004, and we completed a public offering of common stock under our current shelf registration (see discussion below) in December 2004 that provided $47.2 million of net proceeds, after direct costs. For the year ended December 31, 2003, cash flows provided by financing activities totaled $2.9 million including $10.7 million in borrowings and $10.2 million in repayments under our credit facility. In addition, we received $2.4 million in proceeds from the issuance of common stock related to options exercised in 2003 as a result of the increase in our stock price. For the year ended December 31, 2002, cash flows provided by financing activities totaled $10.6 million, including $11.0 million in borrowings and $0.5 million in repayments under our credit facility. In addition, we received $0.1 million in proceeds from the issuance of common stock related to options exercised in 2003.

In connection with the December 2004 common stock offering, the underwriters exercised their over-allotment option in January 2005, which provided funds that were used to reduce our outstanding debt. The combination of unused debt capacity and our current shelf registration will allow us the financial flexibility to participate in larger acquisitions and complete our capital programs as we move into 2005. As of December 31, 2004, we had $45.0 million of unused borrowing capacity under our credit facility.

Credit Facility

In March 2004, the Company entered into a new amended and restated credit facility (the "Credit Facility"), effective December 31, 2003, which permits borrowings up to the lesser of (i) the borrowing base and (ii) $100 million. The Credit Facility matures December 31, 2006 and is secured by substantially all of the Company's assets. Borrowings under the Credit Facility bear interest at a rate equal to prime plus 0.50% or LIBOR plus 2.25%. As of December 31, 2004, $20.0 million in borrowings were outstanding under the Credit Facility and our interest rate was 5.75%.

Effective December 2004, the borrowing base under the Credit Facility was increased from $48.0 million to $65.0 million as a result of the Contango Asset Acquisition and our drilling activities since the last redetermination.

Based on the increase, our available borrowing capacity at December 31, 2004 was $45.0 million. We expect our borrowing base to be redetermined in April 2005 and semiannually thereafter.

The Credit Facility provides for certain restrictions, including but not limited to, limitations on additional borrowings, sales of oil and natural gas properties or other collateral, and engaging in merger or consolidation transactions. The Credit Facility also prohibits dividends and certain distributions of cash or properties and certain liens. The Credit Facility also contains the following financial covenants, among others:

- The EBITDAX to Interest Expense ratio requires that the ratio of (a) our consolidated EBITDAX (defined as EBITDA plus similar non-cash items and exploration and abandonment expenses for such period) for the four fiscal quarters then ended to (b) our consolidated interest expense for the four fiscal quarters then ended, to not be less than 3.5 to 1.0.
- The Working Capital ratio requires that the amount of our consolidated current assets less our consolidated current liabilities, as defined in the agreement, be at least $1.0 million. For the purposes of calculating the Working Capital ratio, current assets is adjusted for unused capacity under credit agreement and hedging and derivative assets and current liabilities is adjusted for derivative and hedging liabilities and asset retirement obligations.
- The Maximum Leverage ratio requires that the ratio, as of the last day of any fiscal quarter, of (a) Total Indebtedness (as defined in the Credit Facility) as of such fiscal quarter to (b) an amount equal to consolidated EBITDAX for the two quarters then ended times two, not be greater than 3.0 to 1.0.

Consolidated EBITDAX is a component of negotiated covenants with our lender and is presented here as part of the Company's disclosure of its covenant obligations.

Shelf Registration Statement

We filed a $150 million shelf registration statement with the SEC, which became effective in May 2004. Under the shelf registration statement, we may issue, from time to time, any combination of debt securities, preferred stock, common stock or warrants for debt securities or equity securities in one or more offerings to those persons who agree to purchase our securities. Net proceeds, terms and pricing of the offering of securities issued under the shelf registration statement will be determined at the time of the offerings. The shelf registration statement does not provide assurance that we will or could sell any such securities. Our ability to utilize our shelf registration statement for the purpose of issuing, from time to time, any combination of debt securities, preferred stock, common stock or warrants for debt securities or equity securities will depend upon, among other things, market conditions and the existence of investors who wish to purchase our securities at prices acceptable to us.

We completed an offering on December 21, 2004 of 3.5 million shares of our common stock under our shelf registration statement, which generated net proceeds to us, before direct costs of the offering, of $47.8 million. These funds were used to finance the Contango Asset Acquisition preliminary adjusted purchase price of $43.2 million and fund the costs of the offering and other general corporate purposes. On January 5, 2005, the underwriters exercised their over-allotment option for an additional 525,000 shares of common stock, which generated net proceeds to us of $7.2 million. These funds were used to reduce our outstanding debt. Each of these sales was made under our shelf registration statement such that at March 15, 2005, we had approximately$91.8 million remaining for issuance under our shelf registration.

Off Balance Sheet Arrangements

The Company currently does not have any off balance sheet arrangements.

Contractual Cash Obligations

The following table summarizes our contractual cash obligations as of December 31, 2004 by payment due date:

	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
			(In thousands)		
Long-term debt (1)	$ 20,000	$ --	$ 20,000	$ --	$ --
Operating leases	5,356	629	1,874	1,245	1,608
Total contractual cash obligations (2)(3)	$ 25,356	$ 629	$ 21,874	$ 1,245	$ 1,608

(1) Excludes amounts for interest expense payable upon outstanding debt. Long-term outstanding under our credit facility is subject to floating interest rates (see note 10 to our consolidated financial statements) and payable on the last day of each calendar month while any loan amounts remain outstanding.
(2) The Company did not have any capital leases or purchase obligations as of December 31, 2004.
(3) The Company has not included its ARO Liability here because historically the actual cash outlay is minimized significantly by the salvage value. In accordance with SFAS No. 143, we do not account for salvage value on our Balance Sheet, but we do not expect to realize the total value that we have accrued.

Risk Management Activities – Derivatives & Hedging

Due to the instability of oil and natural gas prices, we may enter into, from time to time, price-risk management transactions (e.g., swaps, collars and floors) for a portion of our oil and natural gas production to achieve a more predictable cash flow, as well as to reduce exposure from commodity price fluctuations. While the use of these arrangements limit our ability to benefit from increases in the price of oil and natural gas, it also reduces our potential exposure to adverse price movements. Our arrangements, to the extent we enter into any, apply to only a portion of our production, provide only partial price protection against declines in oil and natural gas prices and limits our potential gains from future increases in prices. We also use price-risk management transactions to protect forward pricing as a bidding strategy with respect to acquisition offers and execution. None of these instruments are used for trading purposes. On a quarterly basis, our management sets all of our price-risk management policies, including volumes, types of instruments and counterparties. These policies are implemented by management through the execution of trades by the Chief Financial Officer after consultation and concurrence by the President and Chairman of the Board. Our Board of Directors monitors the Company's price-risk management policies and trades.

All of these price-risk management transactions are considered derivative instruments and accounted for in accordance with SFAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities"*. These derivative instruments are intended to hedge our price risk and may be considered hedges for economic purposes, but certain of these transactions may not qualify for special cash flow hedge accounting. Therefore, depending on the type of transaction and the circumstances, different accounting treatment may apply to the timing and location of the income statement impact, but all derivatives are recorded on the balance sheet at fair value. The following table provides additional information regarding the Company's various derivative and hedging transactions that were recorded at fair value on the balance sheet as of December 31, 2004.

Fair value of contracts outstanding at December 31, 2003	$	120,801
Contracts realized or otherwise settled during the period		(120,801)
Fair value of new contracts when entered into during 2004:		
Asset		1,824,790
Liability		(468,308)
Changes in fair values attributable to changes in valuation techniques and assumptions		--
Other changes in fair values		--
Fair values of contracts outstanding at December 31, 2004	$	1,356,482

The following table details the fair value of our commodity-based derivative and hedging contracts by year of maturity and valuation methodology as of December 31, 2004.

Source of Fair Value	Fair Value of Contracts at December 31, 2004				
	Maturity less than 1 year	Maturity 1-3 years	Maturity 4-5 years	Maturity in excess of 5 years	Total fair value
Prices actively quoted:	--	--	--	--	--
Prices provided by other external sources:					
Asset	1,824,790	--	--	--	1,824,790
Liability	(468,308)	--	--	--	(468,308)
Prices based on models and other valuation methods:	--	--	--	--	--
Total	$ 1,356,482	$ --	$ --	$ --	$ 1,356,482

Tax Matters

At December 31, 2004, we have cumulative net operating loss carryforwards ("NOLs") for federal income tax purposes of approximately $73.9 million, including $17.4 million of NOLs acquired in the Miller merger that expire beginning 2012 through 2022. The estimated NOLs presented herein assume that certain items, primarily intangible drilling costs, have been written off for tax purposes in the current year. However, we have not made a final determination if an election will be made to capitalize all or part of these items for tax purposes in the future.

Recently Issued Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 123(R), *"Share-Based Payment."* This statement requires companies to measure the cost of employee services in exchange for an award of equity instruments based on a grant-date fair value of the award (with limited exceptions), and that cost must generally be recognized over the vesting period. SFAS No. 123(R) amends the original SFAS No. 123 and 95 that had allowed companies to choose between expensing stock options or showing pro forma disclosure only. This statement eliminates the ability to account for share-based compensation transactions using APB Opinion No. 25. We currently account for our stock-based compensation plans under the principles prescribed by APB Opinion No. 25. Accordingly, no stock option compensation cost is reflected in net income, as all options granted under the plan had an exercise price equal to the market value of the underlying common stock on the date of grant. The adoption of SFAS No. 123(R) will impact our results of operations, but will have no impact on our overall financial position. SFAS No. 123(R) becomes effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. We anticipate adopting the provisions of SFAS No. 123(R) in the third quarter of 2005 using the modified prospective method for transition. Under this method we will recognize compensation expense for all stock-based awards granted or modified on or after July 1, 2005, as well as any previously granted awards that are not fully vested as of July 1, 2005. Compensation expense will be measured based on the fair value of the awards previously calculated in developing the pro forma disclosures in accordance with the provisions of SFAS No. 123. We expect the impact to be an increase in deferred compensation expense of approximately $80,000 to $100,000 for 2005. SFAS No. 123(R) also requires the benefits of tax deductions in excess of recognized compensation cost to be reflected as a financing cash flow, rather than as an operating cash flow as currently required. We did not recognize any excess tax deductions during 2004, 2003 or 2002 in connection with the exercise of stock options.

In September 2004, the SEC issued SAB No. 106, *"Interaction of Statement 143 and the Full Cost Rules,"* which we adopted in the fourth quarter of 2004 with no impact on our financial statements. In accordance with SAB No. 106, the amortizable base used to calculate unit-of production depletion includes estimated future development and dismantlement costs, and restoration and abandonment costs, net of estimated salvage-values.

ITEM 7A. QUALITATIVE AND QUANTITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk from changes in interest rates and commodity prices. We use a credit facility, which has a floating interest rate, to finance a portion of our operations. We are not subject to fair value risk resulting from changes in our floating interest rates. The use of floating rate debt instruments provide a benefit due to downward interest rate movements but does not limit us to exposure from future increases in interest rates. Based on the year-end December 31, 2004 outstanding borrowings and a floating interest rate of 5.75%, a 10% change in interest rate would result in an increase or decrease of interest expense of approximately $110,000 on an annual basis.

In the normal course of business we enter into hedging transactions, including commodity price collars, swaps and floors to mitigate our exposure to commodity price movements, but not for trading or speculative purposes. During 2003 and 2004, due to the instability of prices and to achieve a more predictable cash flow, we put in place several natural gas and crude oil collars for a portion of our 2004 production. During 2004, we put in place several natural gas and crude oil collars covering 2005 production. Please refer to Note 9 to our consolidated financial statements. While the use of these arrangements may limit the benefit to us of increases in the price of oil and natural gas, it also limits the downside risk of adverse price movements. The following is a list of contracts outstanding at December 31, 2004:

Transaction Date	Transaction Type		Beginning	Ending	Price Per Unit	Volumes Per Day
Natural Gas:						
05/04	Natural Gas Collar	(1)	01/01/05	03/31/05	$5.00-$10.39	10,000 MMbtu
07/04	Natural Gas Collar	(1)	04/01/05	06/30/05	$5.00-$7.53	10,000 MMbtu
07/04	Natural Gas Collar	(1)	07/01/05	09/30/05	$5.00-$7.67	10,000 MMbtu
10/04	Natural Gas Collar	(1)	01/01/05	12/31/05	$6.00-$9.52	10,000 MMbtu
Crude Oil:						
05/04(08/04)	Crude Oil Collar	(2)(3)	01/01/05	12/31/05	$35.00-$40.00	200/290 Bbl

(1) The Company's current hedging activities for natural gas were entered into on a per MMbtu delivered price basis, using the Houston Ship Channel Index, with settlement for each calendar month occurring five business days following the expiration date.

(2) Hedge accounting is not applied to the Company's collars on crude oil, which were entered into on a per barrel delivered price basis, using the West Texas Intermediate Index, with settlement for each calendar month occurring five business days following the expiration date. The change in fair value is reflected in revenue for the year ended December 31, 2004.

(3) In August 2004, the Company replaced the hedge contract that was outstanding at June 30, 2004 with a new contract that changes the volume and pricing terms. The put option is on 200 Bbl/D and the call option is on 290 Bbl/D. This transact ion was completed at no additional cost to the Company.

At December 31, 2004, the fair value of the outstanding hedge and derivative contracts was a net asset of approximately $1.4 million (See *ITEM 7. "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS* – RISK MANAGEMENT ACTIVITIES – HEDGING & DERIVATIVES *"*). A 10% change in the commodity price per unit, as long as the price is either above the ceiling or below the floor price of each contract, would cause the fair value total of the outstanding net asset position to increase or decrease by approximately $234,200.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

See the Consolidated Financial Statements and Supplementary information listed in the accompanying Index to Consolidated Financial Statements and Supplementary Information on page F-1 herein.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURES

None.

ITEM 9A. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit to the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the Commission's rules and forms, and that information is accumulated and communicated to our management, including Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

We recently discovered an error in a spreadsheet application, which was designed to eliminate intercompany balances. As a result of the error, amounts accumulated in the property account for one subsidiary were also included as an accrued capital expenditure by another subsidiary and inadvertently not eliminated in consolidation. This caused property balances to be overstated. This error in the property balance also impacted our computation of depletion expense and therefore operating expenses, operating income, income tax expense, net income and earnings per share. As a result of the error, we restated our September 30, 2004 financial statements, as reflected in Amendment No. 1 to our Form 10-Q for the quarterly period ended September 30, 2004 and corrected our earnings release for December 31, 2004. The error arose as a result of a change in accounting processes that occurred during the second quarter of 2004 and therefore prior year results were not affected and second quarter 2004 results were not materially affected. In January 2005, we effectively corrected the problem by re-instituting the accounting process we had used prior to the second quarter of 2004. Management has concluded, based on the circumstances involving the spreadsheet error discussed above, that as of December 31, 2004, a material weakness in internal control over financial reporting existed with respect to the design of the Company's controls over the elimination of intercompany balances and transactions.

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, due to the material weakness discussed above, our disclosure controls and procedures were not effective as of December 31, 2004.

We are relying on the exemption provided by Order of the SEC in Release No. 34-50754 (the "Order"). Accordingly we have not included in this Annual Report on Form 10-K filing either "Management's annual report on internal control over financial reporting," required by Item 308(a) of Regulation S-K, or the related "Attestation report of the registered public accounting firm," required by Item 308(b) of Regulation S-K. We will file both of these reports pursuant to an Amendment to our Form 10-K on or before May 2, 2005, in accordance with the Order. As a result of the material weakness discussed above, management's report on internal control will state that internal control over financial reporting was not effective at December 31, 2004 and BDO Seidman, LLP has advised us that they expect that their report on management's assessment of internal control over financial reporting will also indicate that internal control over financial reporting was ineffective as of that date. As a result of our ongoing evaluation of internal control over financial reporting and in preparation for that report, additional problems may be identified which result in disclosure controls and procedures not being effective at December 31, 2004 for other reasons.

There has been no change in our internal controls over financial reporting that occurred during the three months ended December 31, 2004 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information regarding directors and executive officers required under *ITEM 10* will be contained within the definitive Proxy Statement for the Company's 2005 Annual Meeting of Shareholders (the "Proxy Statement") under the headings "Election of Directors," "Standing Committees, Board Organization, Director Nominations and Meetings" and "Compliance with Section 16(a) of the Exchange Act" and is incorporated herein by reference. The Proxy Statement will be filed pursuant to Regulation 14A with the Securities and Exchange Commission not later than 120 days after December 31, 2004. Pursuant to Item 401(b) of Regulation S-K certain of the information required by this item with respect to executive officers of the Company is set forth in Part I of this report.

We have adopted a code of ethics for all employees, officers and directors. That code is available on our website at www.edgepet.com. Any waivers of, or amendments to, the Code of Ethics will be posted on the website.

ITEM 11. EXECUTIVE COMPENSATION

The information required by *ITEM 11* will be contained in the Proxy Statement under the headings "Executive Compensation", "Summary Compensation Table", "Option/SAR Grants","Option/SAR Exercises and 2004 Year-End Option/SAR Values", "401(k) Employee Savings Plan", "Employment Agreements and Change of Control Agreements", "Compensation Committee Interlocks and Insider Participation", "Performance Graph" and "Compensation Committee Report on Executive Compensation" and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by *ITEM 12* will be contained in the Proxy Statement under the headings "Security Ownership of Certain Beneficial Owners and Management" and "Equity Compensation Plan Information" and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by *ITEM 13* will be contained in the Proxy Statement under the heading "Certain Transactions " and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by *ITEM 14* will be contained in the Proxy Statement under the heading "Approval of Appointment of Independent Public Accountants" and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial Statements and Schedules:

1. Financial Statements: See Index to the Consolidated Financial Statements and Supplementary Information immediately following the signature page of this report.

2. Financial Statement Schedule: See Index to the Consolidated Financial Statements and Supplementary Information immediately following the signature page of this report.

(b) Exhibits: The following documents are filed as exhibits to this report:

2.1 — Amended and Restated Combination Agreement by and among (i) Edge Group II Limited Partnership, (ii) Gulfedge Limited Partnership, (iii) Edge Group Partnership, (iv) Edge Petroleum Corporation, (v) Edge Mergeco, Inc. and (vi) the Company, dated as of January 13, 1997 (Incorporated by reference from exhibit 2.1 to the Company's Registration Statement on Form S-4 (Registration No. 333-17269)).

2.2 — Agreement and Plan of Merger dated as of May 28, 2003 among Edge Petroleum Corporation, Edge Delaware Sub Inc. and Miller Exploration Company (Miller") (Incorporated by reference from Annex A to the Joint Proxy Statement/Prospectus contained in the Company's Registration Statement on Form S-4/A filed on October 31, 2003 (Registration No. 333-106484)).

2.3 — Asset Purchase Agreement by and among Contango STEP, L.P., Contango Oil & Gas Company, Edge Petroleum Exploration Company and Edge Petroleum Corporation dated October 7, 2004 (Incorporated by reference from exhibit 2.1 to the Company's Current Report on Form 8-K filed October 12, 2004).

3.1 — Restated Certificate of Incorporation of the Company (Incorporated by reference from exhibit 3.1 to the Company's Registration Statement on Form S-1/A filed on February 5, 1997 (Registration No. 333-17267)).

3.2 — Certificate of Amendment to the Restated Certificate of Incorporation of the Company (Incorporated by reference from exhibit 3.1 to the Company's Registration Statement on Form S1/A filed on February 5, 1997 (Registration No. 333-17267)).

3.3 — Bylaws of the Company (Incorporated by Reference from exhibit 3.3 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1999).

3.4 — First Amendment to Bylaws of the Company on September 28, 1999 (Incorporated by reference from exhibit 3.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1999).

3.5 — Second Amendment to Bylaws of the Company on May 7, 2003 (Incorporated by reference from exhibit 3.4 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2003).

4.1 — Third Amended and Restated Credit Agreement dated December 31, 2003 among Edge Petroleum Corporation, Edge Petroleum Exploration Company, Edge Petroleum Operating Company, Inc., Miller Oil Corporation, and Miller Exploration Company, as borrowers, the lenders thereto and Union Bank of California, N.A., a national banking association, as Agent (Incorporated by reference from Exhibit 4.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).

4.2 — Common Stock Subscription Agreement dated as of April 30, 1999 between the Company and the purchasers named therein (Incorporated by reference from exhibit 4.5 to the Company's Quarterly Report on Form 10-Q/A for the quarter ended March 31, 1999).

4.3 — Registration Rights Agreement by and among Edge Petroleum Corporation, Guardian Energy Management Corp., Kelly E. Miller and the Debra A. Miller Trust, dated December 4, 2003 (Incorporated by reference from exhibit 4.2 to the Company's Registration Statement on Form S-3 filed on February 3, 2004 (Registration No. 333-112462)).

4.4 — Miller Exploration Company Stock Option and Restricted Stock Plan of 1997 (Incorporated by reference from exhibit 10.1(a) to Miller Exploration Company's Annual Report on Form 10-K for the year ended December 31, 1997 (File No. 000-23431)).

4.5 — Amendment No. 1 to the Miller Exploration Company Stock Option and Restricted Stock Plan of 1997 (Incorporated by reference to Exhibit 4.2 from Miller Exploration Company's Registration Statement on Form S-8 filed on April 11, 2001 (Registration No. 333-58678)).

4.6 — Amendment No. 2 to the Miller Exploration Company Stock Option and Restricted Stock Plan of 1997 (Incorporated by reference from Exhibit 4.3 to Miller Exploration Company's Registration Statement on Form S-8 filed on April 11, 2001 (Registration No. 333-58678)).

4.7 — Form of Miller Stock Option Agreement (Incorporated by reference from exhibit 10.1(b) to Miller Exploration Company's Annual Report on Form 10-K for the year ended December 31, 1997 (File No. 000-23431)).

†10.1— Form of Indemnification Agreement between the Company and each of its directors (Incorporated by reference from exhibit 10.7 to the Company's Registration Statement on Form S-4 (Registration No. 333-17269)).

†10.2— Stock Option Plan of Edge Petroleum Corporation, a Texas corporation (Incorporated by reference from exhibit 10.13 to the Company's Registration Statement on Form S-4 (Registration No. 333-17269)).

†10.3— Employment Agreement dated as of November 16, 1998, by and between the Company and John W. Elias (Incorporated by reference from 10.12 to the Company's Annual Report on Form 10-K for the year ended December 31, 1998).

†10.4— Incentive Plan of Edge Petroleum Corporation as Amended and Restated Effective as of June 1, 2004 (Incorporated by reference from exhibit 10.9 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004).

†10.5— Edge Petroleum Corporation Incentive Plan "Standard Non-Qualified Stock Option Agreement" by and between Edge Petroleum Corporation and the Officers named therein (Incorporated by reference from exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1999).

†10.6— Edge Petroleum Corporation Incentive Plan "Director Non-Qualified Stock Option Agreement" by and between Edge Petroleum Corporation and the Directors named therein (Incorporated by reference from exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1999).

†10.7— Severance Agreements by and between Edge Petroleum Corporation and the Officers of the Company named herein (Incorporated by reference from exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1999).

†10.8– Form of Director's Restricted Stock Award Agreement under the Incentive Plan of Edge Petroleum Corporation (Incorporated by reference from exhibit 10.12 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004).

†10.9— Form of Employee Restricted Stock Award Agreement under the Incentive Plan of Edge Petroleum Corporation (Incorporated by reference from exhibit 10.15 to the Company's Quarterly Report on Form 10-Q/A for the quarterly period ended March 31, 1999).

†10.10— Edge Petroleum Corporation Amended and Restated Elias Stock Incentive Plan. (Incorporated by reference from exhibit 4.5 to the Company's Registration Statement on Form S-8 filed May 30, 2001 (Registration No. 333-61890)).

†10.11— Form of Edge Petroleum Corporation John W. Elias Non-Qualified Stock Option Agreement (Incorporated by reference from exhibit 4.6 to the Company's Registration Statement on Form S-8 filed May 30, 2001 (Registration No. 333-61890)).

*†10.12— Summary of Compensation of Non-Employee Directors.

*†10.13— Salaries and Other Compensation of Executive Officers.

*†10.14— Description of 2004 Bonus Program for Executive Officers.

*21.1— Subsidiaries of the Company.

*23.1— Consent of BDO Seidman, LLP.

*23.2— Consent of Ryder Scott Company.

*23.3— Consent of W. D. Von Gonten & Co.

*31.1— Certification by John W. Elias, Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

*31.2— Certification by Michael G. Long, Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

*32.1— Certification by John W. Elias, Chief Executive Officer, pursuant to 18 USC Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

*32.2— Certification by Michael G. Long, Chief Financial Officer, pursuant to 18 USC Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

*99.1— Summary of Reserve Report of Ryder Scott Company Petroleum Engineers as of December 31, 2004.

*99.2— Summary of Reserve Report of W. D. Von Gonten & Co. Petroleum Engineers as of December 31, 2004.

* Filed herewith.
† Denotes management or compensatory contract, arrangement or agreement.

SIGNATURES

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

Edge Petroleum Corporation

/S/ John W. Elias
John W. Elias
Chief Executive Officer and Chairman of the Board

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

/S/ John W. Elias John W. Elias Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	Date: March 16, 2005
/S/ Michael G. Long Michael G. Long Senior Vice President and Chief Financial Officer (Principal Financial and Principal Accounting Officer)	Date: March 16, 2005
/S/ Thurmon M. Andress Thurmon Andress Director	Date: March 16, 2005
/S/ Vincent S. Andrews Vincent Andrews Director	Date: March 16, 2005
/S/ Joseph R. Musolino Joseph R. Musolino Director	Date: March 16, 2005
/S/ Stanley S. Raphael Stanley S. Raphael Director	Date: March 16, 2005
/S/ John Sfondrini John Sfondrini Director	Date: March 16, 2005
/S/ Robert W. Shower Robert W. Shower Director	Date: March 16, 2005
/S/ David F. Work David F. Work Director	Date: March 16, 2005

EDGE PETROLEUM CORPORATION

Index to Consolidated Financial Statements and Supplementary Information

CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

All schedules for which provision is made in the applicable accounting regulations of the Securities and Exchange Commission are not required under the related instructions or are inapplicable and therefore have been omitted.

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Edge Petroleum Corporation
Houston, Texas

We have audited the accompanying consolidated balance sheets of Edge Petroleum Corporation as of December 31, 2004 and 2003, and the related consolidated statements of operations, other comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2004. 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 financial statements referred to above present fairly, in all material respects, the financial position of Edge Petroleum Corporation at December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

BDO SEIDMAN, LLP

Houston, Texas
March 14, 2005

EDGE PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

	December 31, 2004	December 31, 2003
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,267,423	$ 1,327,081
Accounts receivable, trade, net of allowance of $525,248 as of December 31, 2004 and 2003	13,715,890	8,889,734
Accounts receivable, joint interest owners and other, net of allowance of $82,000 as of December 31, 2004 and 2003	5,911,073	1,797,877
Deferred income taxes	660,223	1,138,492
Derivative financial instruments	1,824,790	120,801
Other current assets	1,445,923	1,186,987
Total current assets	25,825,322	14,460,972
PROPERTY AND EQUIPMENT, Net – full cost method of accounting for oil and natural gas properties (including unevaluated costs of $15.5 million and $5.0 million at December 31, 2004 and 2003, respectively)	165,840,345	97,980,757
OTHER ASSETS	284,280	--
DEFERRED INCOME TAXES	--	5,570,137
TOTAL ASSETS	$ 191,949,947	$ 118,011,866
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable, trade	$ 3,141,235	$ 1,732,935
Accrued liabilities	13,065,487	11,456,036
Derivative financial instruments	468,308	--
Asset retirement obligation – current portion	193,647	323,513
Total current liabilities	16,868,677	13,512,484
ASSET RETIREMENT OBLIGATION – long-term portion	1,995,441	1,488,482
DEFERED TAX LIABILITY	2,618,934	--
LONG-TERM DEBT	20,000,000	21,000,000
Total liabilities	41,483,052	36,000,966
COMMITMENTS AND CONTINGENCIES (Note 12)		
STOCKHOLDERS' EQUITY		
Preferred stock, $0.01 par value; 5,000,000 shares authorized; none issued and outstanding	--	--
Common stock, $0.01 par value; 25,000,000 shares authorized; 16,535,901 and 12,581,032 shares issued and outstanding at December 31, 2004 and 2003, respectively	165,359	125,810
Additional paid-in capital	126,957,059	75,282,007
Retained earnings	22,095,807	6,966,557
Accumulated other comprehensive income (loss)	1,248,670	(363,474)
Total stockholders' equity	150,466,895	82,010,900
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 191,949,947	$ 118,011,866

See accompanying notes to the consolidated financial statements.

EDGE PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2004	2003	2002
OIL AND NATURAL GAS REVENUE:			
Oil and natural gas sales	$ 66,965,411	$ 38,381,597	$ 21,238,244
Loss on hedging and derivatives	(2,460,063)	(4,455,590)	(326,950)
Total revenue	64,505,348	33,926,007	20,911,294
OPERATING EXPENSES:			
Oil and natural gas operating expenses including production and ad valorem taxes	9,308,770	5,115,794	3,831,590
Depletion, depreciation, amortization and accretion	21,927,874	13,577,279	10,426,667
General and administrative expenses:			
Deferred compensation expense – repriced options	1,135,628	1,219,349	3,385
Deferred compensation expense – restricted stock	498,372	372,151	399,249
Other general and administrative	7,812,970	5,540,140	4,826,793
Total operating expenses	40,683,614	25,824,713	19,487,684
OPERATING INCOME	23,821,734	8,101,294	1,423,610
OTHER INCOME (EXPENSE):			
Interest expense, net of amounts capitalized	(331,399)	(678,805)	(143,280)
Amortization of deferred loan costs	(142,135)	--	(84,479)
Interest income	36,075	16,518	26,954
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	23,384,275	7,439,007	1,222,805
INCOME TAX EXPENSE	(8,255,025)	(2,731,132)	(473,060)
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	15,129,250	4,707,875	749,745
CUMULATIVE EFFECT OF ACCOUNTING CHANGE	--	(357,825)	--
NET INCOME	$ 15,129,250	$ 4,350,050	$ 749,745
BASIC EARNINGS PER SHARE:			
Income before cumulative effect of accounting change	$ 1.16	$ 0.48	$ 0.08
Cumulative effect of accounting change	--	(0.03)	--
Basic earnings per share	$ 1.16	$ 0.45	$ 0.08
DILUTED EARNINGS PER SHARE:			
Income before cumulative effect of accounting change	$ 1.11	$ 0.47	$ 0.08
Cumulative effect of accounting change	--	(0.03)	--
Diluted earnings per share	$ 1.11	$ 0.44	$ 0.08
BASIC WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING	13,029,075	9,726,140	9,384,097
DILUTED WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING	13,648,261	9,987,551	9,605,571

See accompanying notes to the consolidated financial statements.

EDGE PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OTHER COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2004	2003	2002
NET INCOME	$ 15,129,250	$ 4,350,050	$ 749,745
OTHER COMPREHENSIVE INCOME (LOSS), net of tax:			
Change in fair value of outstanding hedging and derivative instruments (1)	1,248,670	(363,474)	(840,996)
Reclassification of hedging and derivative losses (2)	363,474	840,996	--
Other comprehensive income (loss)	1,612,144	477,522	(840,996)
COMPREHENSIVE INCOME (LOSS)	$ 16,741,394	$ 4,827,572	$ (91,251)
(1) net of income tax (expense) benefit of	$ 672,360	$ (201,975)	$ (452,844)
(2) net of income tax (expense) benefit of	$ 201,975	$ 452,844	$ --

See accompanying notes to the consolidated financial statements.

EDGE PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2004	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 15,129,250	$ 4,350,050	$ 749,745
Adjustments to reconcile net income to net cash provided by operating activities:			
Cumulative effect of accounting change	--	357,825	--
Unrealized loss on the fair value of derivatives	564,548	--	--
Depletion, depreciation, amortization and accretion	21,927,874	13,577,279	10,426,667
Amortization of deferred loan costs	142,135	--	84,479
Deferred tax provision	8,255,025	2,731,132	473,060
Non-cash compensation expense	1,634,000	1,591,500	402,634
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable, trade	(4,139,906)	(3,137,319)	691,989
(Increase) decrease in accounts receivable, joint interest owners	(4,113,196)	(1,187,958)	113,555
(Increase) decrease in other assets	(258,936)	(429,403)	141,945
Increase (decrease) in accounts payable, trade	1,408,300	(1,767,685)	121,521
Increase (decrease) in accrued interest payable	--	(127,698)	127,698
Increase (decrease) in accrued liabilities	1,721,248	7,940,421	(2,925,712)
Net cash provided by operating activities	42,270,342	23,898,144	10,407,581
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(89,470,369)	(33,560,102)	(19,609,639)
Proceeds from the sale of oil and natural gas properties	60,000	330,096	354,294
Cash acquired in merger with Miller Exploration Company, net of acquisition costs	--	5,159,806	--
Net cash used in investing activities	(89,410,369)	(28,070,200)	(19,255,345)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings from long-term debt	27,000,000	10,700,000	11,000,000
Payments on long-term debt	(28,000,000)	(10,200,000)	(500,000)
Net proceeds from issuance of common stock	49,506,784	2,430,961	122,653
Loan costs	(426,415)	--	--
Net cash provided by financing activities	48,080,369	2,930,961	10,622,653
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	940,342	(1,241,095)	1,774,889
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	1,327,081	2,568,176	793,287
CASH AND CASH EQUIVALENTS, END OF YEAR	$ 2,267,423	$ 1,327,081	$ 2,568,176

See accompanying notes to the consolidated financial statements.

EDGE PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock		Additional	Retained	Accumulated Other	Total
	Shares	Amount	Paid-in Capital	Earnings (Deficit)	Comprehensive Income (Loss)	Stockholders' Equity
BALANCE, DECEMBER 31, 2001	9,305,079	$ 93,051	$ 56,139,451	$ 1,866,762	$ --	$ 58,099,264
Issuance of common stock	111,175	1,112	121,541	--	--	122,653
Deferred compensation expense – restricted stock	--	--	399,249	--	--	399,249
Deferred compensation expense – repriced options	--	--	3,385	--	--	3,385
Change in valuation of hedging instruments	--	--	--	--	(840,996)	(840,996)
Net income	--	--	--	749,745	--	749,745
BALANCE, DECEMBER 31, 2002	9,416,254	94,163	56,663,626	2,616,507	(840,996)	58,533,300
Issuance of common stock	3,164,778	31,647	16,889,740	--	--	16,921,387
Deferred compensation expense – restricted stock	--	--	372,151	--	--	372,151
Deferred compensation expense – repriced options	--	--	1,219,349	--	--	1,219,349
Tax benefit associated with exercise of non-qualified stock options	--	--	137,141	--	--	137,141
Reclassification of hedging losses	--	--	--	--	840,996	840,996
Change in valuation of hedging instruments	--	--	--	--	(363,474)	(363,474)
Net income	--	--	--	4,350,050	--	4,350,050
BALANCE, DECEMBER 31, 2003	12,581,032	125,810	75,282,007	6,966,557	(363,474)	82,010,900
Issuance of common stock	3,954,869	39,549	49,579,032	--	--	49,618,581
Deferred compensation expense – restricted stock	--	--	498,372	--	--	498,372
Deferred compensation expense – repriced options	--	--	1,135,628	--	--	1,135,628
Tax benefit associated with exercise of non-qualified stock options	--	--	462,020	--	--	462,020
Reclassification of hedging losses	--	--	--	--	363,474	363,474
Change in valuation of hedging instruments	--	--	--	--	1,248,670	1,248,670
Net income	--	--	--	15,129,250	--	15,129,250
BALANCE, DECEMBER 31, 2004	16,535,901	$ 165,359	$ 126,957,059	$ 22,095,807	$ 1,248,670	$ 150,466,895

See accompanying notes to the consolidated financial statements.

EDGE PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND NATURE OF OPERATIONS

General - Edge Petroleum Corporation (the "Company") was organized as a Delaware corporation in August 1996 in connection with its initial public offering and the related combination of certain entities that held interests in Edge Joint Venture II (the "Joint Venture") and certain other oil and natural gas properties; herein referred to as the "Combination". In a series of transactions the Company issued an aggregate of 4,701,361 shares of common stock and received in exchange 100 percent of the ownership interests in the Joint Venture and certain other oil and natural gas properties. In March 1997, and contemporaneously with the Combination, the Company completed the initial public offering of 2,760,000 shares of its common stock (the "Offering"). In December 2003, the Company completed a merger with Miller Exploration Company ("Miller") in a stock for stock transaction, in which the Company issued 2.6 million shares of common stock to the shareholders of Miller.

Nature of Operations - The Company is an independent energy company engaged in the exploration, development, acquisition and production of oil and natural gas. The Company's resources and assets are managed and its results are reported as one operating segment. The Company conducts its operations primarily along the onshore United States Gulf Coast, with its primary emphasis in south Texas, Mississippi, Louisiana and Southeast New Mexico. In its exploration efforts the Company emphasizes an integrated geologic interpretation method incorporating 3-D seismic technology and advanced visualization and data analysis techniques utilizing state-of-the-art computer hardware and software.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation - The consolidated financial statements include the accounts of all majority owned subsidiaries of the Company, including Edge Petroleum Operating Company Inc., Edge Petroleum Exploration Company, Miller Oil Corporation, and Miller Exploration Company, which are 100 percent owned subsidiaries of the Company. All intercompany balances and transactions have been eliminated in consolidation.

Changes in Accounting Principles – None.

Cash and Cash Equivalents - The Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents.

Financial Instruments - The Company's financial instruments consist of cash, receivables, payables, long-term debt and oil and natural gas commodity hedges. The carrying amount of cash, receivables and payables approximates fair value because of the short-term nature of these items. The carrying amount of long-term debt as of December 31, 2004 and 2003 approximates fair value because the interest rates are variable and reflective of market rates. Our hedging instruments are reflected at fair value based on quotes obtained from our counterparties.

Revenue Recognition - The Company recognizes oil and natural gas revenue from its interests in producing wells as oil and natural gas is produced and sold from those wells. Oil and natural gas sold by the Company is not significantly different from the Company's share of production.

Allowance for Doubtful Accounts - The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectibility. Many of Edge's receivables are from joint interest owners on properties of which the Company is the operator. Thus, Edge may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Generally, the Company's crude oil and natural gas receivables are collected within two months. The Company accrues a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of any reserve may be reasonably estimated. As of December 31, 2004 and 2003, the Company had an allowance for doubtful accounts of $525,248 related to trade receivables and $82,000 related to joint interest receivables (see Note 3).

Inventories - Inventories consist principally of tubular goods and production equipment, stated at the lower of weighted-average cost or market.

Other Property, Plant & Equipment - Depreciation of other office furniture and equipment and computer hardware and software is provided using the straight-line method based on estimated useful lives ranging from three to seven years.

Oil and Natural Gas Properties - Investments in oil and natural gas properties are accounted for using the full cost method of accounting. The accounting for our business is subject to special accounting rules that are unique to the oil and gas industry and there are two allowable methods of accounting for oil and gas business activities: the successful-efforts method and the full-cost method. There are several significant differences between these methods. Among these differences is that, under the successful-efforts method, costs such as geological and geophysical ("G&G"), exploratory dry holes and delay rentals are expensed as incurred whereas under the full-cost method these types of charges are capitalized to their respective full-cost pool. In the measurement of impairment of oil and gas properties, the successful-efforts method of accounting follows the guidance provided in Statement of Financial Accounting Standards ("SFAS") No. 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets*," where the first measurement for impairment is to compare the net book value of the related asset to its undiscounted future cash flows using commodity prices consistent with management expectations. The full-cost method follows guidance provided in Securities and Exchange Commission ("SEC") Regulation S-X Rule 4-10, where impairment is determined by comparing the net book value (full-cost pool) to the future net cash flows discounted at 10% using commodity prices in effect at the end of the reporting period.

In accordance with the full-cost method of accounting, all costs associated with the exploration, development and acquisition of oil and natural gas properties, including salaries, benefits and other internal costs directly attributable to these activities are capitalized within a cost center. The Company's oil and natural gas properties are located within the United States of America, which constitutes one cost center. The Company capitalized $2.2 million, $1.7 million, and $1.5 million of general and administrative costs in 2004, 2003 and 2002, respectively. The Company also capitalizes a portion of interest expense on borrowed funds related to unproved oil and gas properties. The Company capitalized approximately $701,700, $244,500, and $623,400 of interest costs in 2004, 2003 and 2002, respectively.

Oil and natural gas properties are amortized using the unit-of-production method using estimates of proved reserve quantities. Investments in unproved properties are not amortized until proved reserves associated with the prospects can be determined or until impairment occurs. Unproved oil and natural gas properties consist of the cost of unevaluated leaseholds, cost of seismic data, exploratory and developmental wells in progress, and secondary recovery projects before the assignment of proved reserves. Oil and natural gas properties include costs of $15.5 million and $5.0 million at December 31, 2004 and 2003, respectively, related to unproved property, which were excluded from capitalized costs being amortized. Unproved properties are evaluated quarterly, and as needed, for impairment on a property-by-property basis. Factors considered by management in its impairment assessment include drilling results by the Company and other operators, the terms of oil and natural gas leases not held by production, production response to secondary recovery activities and available funds for exploration and development. If the results of an assessment indicate that an unproved property is impaired, the amount of impairment is added to the proved oil and natural gas property costs to be amortized. In September 2004, the Securities and Exchange Commission ("SEC") issued SEC Staff Accounting Bulletin ("SAB") No. 106, *"Interaction of Statement 143 and the Full Cost Rules,"* which the Company adopted in the fourth quarter of 2004 with no impact on the Company's financial statements. In accordance with SAB No. 106, the amortizable base used to calculate unit-of production depletion includes estimated future development and dismantlement costs, and restoration and abandonment costs, net of estimated salvage values. The depletion rates per Mcfe for the years ended December 31, 2004, 2003 and 2002 were $1.78, $1.59, and $1.39, respectively.

In addition, the capitalized costs of oil and natural gas properties are subject to a "ceiling test," whereby to the extent that such capitalized costs subject to amortization in the full cost pool (net of depletion, depreciation and amortization, asset retirement obligations and related deferred taxes) exceed the present value (using 10% discount rate) of estimated future net after-tax cash flows from proved oil and natural gas reserves, such excess costs are charged to operations. Once incurred, an impairment of oil and natural gas properties is not reversible at a later date. In accordance with SAB No. 103, *"Update of Codification of Staff Accounting Bulletins,"* derivative instruments qualifying as cash flow hedges are included in the computation of limitation on capitalized costs. The period-end price was between the cap and floor established by the Company's hedge contracts at December 31, 2004 and thus no impact was included in the calculation. Impairment of oil and natural gas properties is assessed on a quarterly basis in conjunction with the Company's quarterly filings with the SEC. The period-end price was within the collar established by the Company's hedges at December 31, 2004 and thus did not affect prices used in this calculation. No adjustment related to the ceiling test was required during the years ended December 31, 2004, 2003, or 2002.

Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves.

In March 2004, the Emerging Issues Task Force ("EITF") reached a consensus that mineral rights, as defined in EITF Issue No. 04-2, *"Whether Mineral Rights Are Tangible or Intangible Assets,"* are tangible assets and that they should be removed as examples of intangible assets in SFAS Nos. 141, *"Business Combinations,"* and SFAS No. 142, *"Goodwill and Other Intangible Assets."* The Financial Accounting Standards Board ("FASB") has recently ratified this consensus and directed the FASB staff to amend SFAS Nos. 141 and 142 through the issuance of FASB Staff Positions ("FSP") Nos. FAS 141-1 and FAS 142-1, *"Interaction of FASB Statements No. 141, Business Combinations, and No. 142, Goodwill and Other Intangible Assets, and EITF Issue No. 04-2, "Whether Mineral Rights Are Tangible or Intangible Assets."* In addition, FSP FAS 142-2, *"Application of FASB Statement No. 142, Goodwill and Other Intangible Assets, to Oil- and Gas-Producing Entities"* confirms that SFAS No. 142 does not change the balance sheet classification or disclosures of mineral rights of oil and gas producing enterprises. Historically, we have included the costs of such mineral rights as tangible assets, which is consistent with the EITF's consensus. As such, EITF 04-2 and the related FSPs have not affected our consolidated financial statements.

Asset Retirement Obligations – The Company accounts for asset retirement obligations under the provisions of SFAS No. 143, *"Accounting for Asset Retirement Obligations,"* which provides for an asset and liability approach to accounting for Asset Retirement Obligations ("ARO"). Under this method, when legal obligations for dismantlement and abandonment costs, excluding salvage values, are incurred, a liability is recorded at fair value and the carrying amount of the related oil and gas properties is increased. Accretion of the liability is recognized each period using the interest method of allocation and the capitalized cost is depleted over the useful life of the related asset. The Company adopted this policy effective January 1, 2003, using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated accretion and depletion. The cumulative effect of the adoption of SFAS No. 143 and the change in accounting principle was a charge to net income during the first quarter of 2003 of $357,825, net of taxes of $192,675. (See Note 7)

Income Taxes - The Company accounts for income taxes under the provisions of SFAS No. 109, *"Accounting for Income Taxes,"* which provides for an asset and liability approach to accounting for income taxes. Under this approach, deferred tax assets and liabilities are recognized based on anticipated future tax consequences, using currently enacted tax laws, attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax bases (see Note 14).

Stock-Based Compensation - The Company accounts for stock compensation plans under the intrinsic value method of Accounting Principles Board ("APB") Opinion No. 25, *"Accounting for Stock Issued to Employees."* No compensation expense is recognized for stock options that had an exercise price equal to the market value of the underlying common stock on the date of grant. As allowed by SFAS No. 123, *"Accounting for Stock Based Compensation,"* the Company has continued to apply APB Opinion No. 25 for purposes of determining net income, but SFAS No. 123, as amended, requires prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based compensation and the effect of the method used on reported results. SFAS No. 123 was revised in December 2004 to eliminate the use of APB Opinion No. 25 after the second quarter of 2005 (see Recently Issued Accounting Pronouncements below).

Had compensation expense for stock-based compensation been determined based on the fair value at the date of grant, our net income and earnings per share would have been as follows:

	Year Ended December 31,		
	2004	2003	2002
Net income as reported	$ 15,129,250	$ 4,350,050	$ 749,745
Add:			
Stock based employee compensation expense included in reported net income, net of related income tax	1,062,100	771,681	2,075
Deduct:			
Total stock based employee compensation expense determined under fair value based method for all awards, net of related income tax	(501,907)	(260,850)	(261,927)
Pro forma net income	$ 15,689,443	$ 4,860,881	$ 489,893
Earnings Per Share			
Basic – as reported	$ 1.16	$ 0.45	$ 0.08
Basic – pro forma	1.20	0.50	0.05
Diluted – as reported	$ 1.11	$ 0.44	$ 0.08
Diluted – pro forma	1.15	0.49	0.05

The weighted-average fair value of each option granted during 2004, 2003 and 2002 was $11.03, $3.24, and $4.19, respectively. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions: expected stock price volatility of 72%, 73%, and 77% in 2004, 2003 and 2002, respectively; risk free interest rate of 3.76%, 3.76%, and 3.82% in 2004, 2003 and 2002, respectively; average expected option lives of ten years for 2004 and eight years in 2003 and 2002, respectively; and over the vesting period of such options a forfeiture rate of 0% for 2004 and 10% for 2003 and 2002.

The Company is also subject to reporting requirements of FASB Interpretation No. ("FIN") 44, "*Accounting for Certain Transactions involving Stock Compensation,*" that requires variable accounting for re-priced stock options. A non-cash charge to deferred compensation expense is recorded if the market price of the Company's common stock at the end of a reporting period is greater than the exercise price of certain re-priced stock options. After the first such adjustment is made, each subsequent period is adjusted upward or downward to the extent that the market price exceeds the exercise price of the options. The charge is related to non-qualified stock options granted to employees and directors in prior years and re-priced in May 1999, as well as certain options newly issued in conjunction with the repricing (see Note 16). A pre-tax charge of $1.1 million, $1.2 million and $3,385 was required for the years ended December 31, 2004, 2003 and 2002, respectively.

Earnings Per Share - The Company accounts for its earnings per share in accordance with SFAS No. 128, "*Earnings per Share,*" which requires the presentation of "basic" and "diluted" EPS on the face of the income statement. Basic earnings per common share amounts are calculated using the average number of common shares outstanding during each period. Diluted earnings per share assumes the exercise of all stock options and warrants having exercise prices less than the average market price of the common stock using the treasury stock method (see Note 16).

Derivatives and Hedging Activities - The Company adopted SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities*" effective January 1, 2001. The statement, as amended by SFAS No. 137 "*Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB Statement No. 133 - an Amendment of FASB Statement No. 133*" and SFAS No. 138, "*Accounting for Certain Derivative Instruments and Certain Hedging Activities - an Amendment of FASB Statement No. 133*", requires that all derivatives be recognized as either assets or liabilities and measured at fair value, and changes in the fair value of derivatives be reported in current earnings, unless the derivative qualifies for special hedge accounting treatment. If the derivative is designated as a cash flow hedge and the intended use of the derivative is to hedge the exposure to variability in expected future cash flows then the changes in the fair value of the derivative instrument will generally be reported in Other Comprehensive Income ("OCI"). The gains and losses on the derivative instrument that are reported in OCI will be reclassified to earnings in the period in which earnings are impacted by the hedged item (see Note 9). Upon adoption of SFAS No. 133, the Company recorded a transition adjustment of approximately $(1.1) million in accumulated other comprehensive income to record the fair value of the natural gas hedges that were outstanding at that date. If hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, the derivative will continue to be carried on the balance sheet at its fair value and gains and losses that were accumulated in other comprehensive income will be recognized in earnings immediately.

Comprehensive Income - The Company follows the provisions of SFAS No. 130, "*Reporting Comprehensive Income*". SFAS No. 130 establishes standards for reporting and presentation of comprehensive income and its components. SFAS No. 130 requires that all items that are required to be recognized under accounting standards as components of comprehensive income be reported in a financial statement that is displayed with the same prominence as other financial statements. In accordance with the provisions of SFAS No. 130, the Company has presented the components of comprehensive income below the total for net income on the face of the consolidated statements of operations. For the years ended December 31, 2004, 2003 and 2002, the only component of other comprehensive income have been changes in fair value of hedging instruments and reclassifications of hedging gains and losses.

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 and disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates.

Significant estimates include volumes of oil and gas reserves used in calculating depletion of proved oil and natural gas properties, future net revenues and abandonment obligations, impairment of undeveloped properties, future income taxes and related assets/liabilities, bad debts, derivatives, contingencies and litigation. Oil and natural gas reserve estimates, which are the basis for unit-of-production depletion and the ceiling test, have numerous inherent uncertainties. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. In addition, reserve estimates are vulnerable to changes in wellhead prices of crude oil and natural gas. Such prices have been volatile in the past and can be expected to be volatile in the future.

Concentration of Credit Risk - Substantially all of the Company's accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the oil and natural gas industry. This concentration of customers and joint interest owners may impact the Company's overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Historically, the Company has not experienced significant credit losses on such receivables; however, in 2001, the Company reserved $525,248 related to nonpayments from two purchasers of the Company's oil and natural gas. No bad debt expense was recorded in 2004 or 2003. The Company cannot ensure that similar such losses may not be realized in the future.

Recently Issued Accounting Pronouncements – In December 2004, the FASB issued SFAS No. 123(R), "*Share-Based Payment.*" This statement requires companies to measure the cost of employee services in exchange for an award of equity instruments based on a grant-date fair value of the award (with limited exceptions), and that cost must generally be recognized over the vesting period. SFAS No. 123(R) amends the original SFAS No. 123 and 95 that had allowed companies to choose between expensing stock options or showing pro forma disclosure only. This statement eliminates the ability to account for share-based compensation transactions using APB Opinion No. 25. We currently account for our stock-based compensation plans under the principles prescribed by APB Opinion No. 25. Accordingly, no stock option compensation cost is reflected in net income, as all options granted under the plan had an exercise price equal to the market value of the underlying common stock on the date of grant. The adoption of SFAS No. 123(R) will impact our results of operations, but will have no impact on our overall financial position. SFAS No. 123(R) becomes effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. We anticipate adopting the provisions of SFAS No. 123(R) in the third quarter of 2005 using the modified prospective method for transition. Under this method we will recognize compensation expense for all stock-based awards granted or modified on or after July 1, 2005, as well as any previously granted awards that are not fully vested as of July 1, 2005. Compensation expense will be measured based on the fair value of the awards previously calculated in developing the pro forma disclosures in accordance with the provisions of SFAS No. 123 (see Stock-Based Compensation above). We expect the impact to be an increase in deferred compensation expense of approximately $80,000 to $100,000 for 2005. SFAS No. 123(R) also requires the benefits of tax deductions in excess of recognized compensation cost to be reflected as a financing cash flow, rather than as an operating cash flow as currently required. We did not recognize any excess tax deductions during 2004, 2003 or 2002 in connection with the exercise of stock options.

In September 2004, the SEC issued SAB No. 106, *"Interaction of Statement 143 and the Full Cost Rules,"* which the Company adopted in the fourth quarter of 2004 with no impact on the Company's financial statements. In accordance with SAB No. 106, the amortizable base used to calculate unit-of production depletion includes estimated future development and dismantlement costs, and restoration and abandonment costs, net of estimated salvage values.

Reclassifications - Certain reclassifications of prior period statements have been made to conform to current reporting practices.

3. ACCOUNTS RECEIVABLE AND ALLOWANCE FOR DOUBTFUL ACCOUNTS

Below are the components of Accounts Receivable, Joint Interest Owners and Other, as of December 31, 2004 and 2003:

	December 31,	
	2004	2003
Joint interest owners	$ 2,351,749	$ 1,544,445
Contango Asset Acquisition Purchase Price Adjustment (1)	3,366,400	--
Other Receivables (2)	274,924	335,432
Allowance for Doubtful Accounts Receivable (joint interest owners)	(82,000)	(82,000)
Net Accounts Receivable, joint interest owners and other	$ 5,911,073	$ 1,797,877

(1) This amount represents the accrual of revenues, net of expenses for the results of operations between November 1, 2004 and December 29, 2004 of the acquired properties (see note 6 below).

(2) Other receivables represent various miscellaneous refunds or credits that the Company is due that do not relate to Joint Interest Billings or Trade Receivables.

The following table sets forth changes in the Company's allowance for doubtful accounts for the years ended December 31, 2004, 2003 and 2002:

	Balance at Beginning of Year	Charged to Costs and Expenses	Deductions and Other	Balance at End of Year
Year ended December 31, 2004:				
Allowance for doubtful accounts	$ 607,248	$ --	$ --	$ 607,248
Year ended December 31, 2003:				
Allowance for doubtful accounts	$ 607,248	$ --	$ --	$ 607,248
Year ended December 31, 2002:				
Allowance for doubtful accounts	$ 688,248	$ --	$ 81,000	$ 607,248

4. OTHER CURRENT ASSETS

Below are the components of other current assets as of December 31, 2004 and 2003:

	December 31, 2004	December 31, 2003
Prepaid Insurance	$ 426,966	$ 745,499
Prepayments and Deposits to Vendors	498,282	118,167
Inventory (1)	520,675	323,321
	$ 1,445,923	$ 1,186,987

(1) Consists of tubular goods and production equipment for wells and facilities.

5. PROPERTY AND EQUIPMENT

At December 31, 2004 and 2003, property and equipment consisted of the following:

	December 31, 2004	December 31, 2003
Developed oil and natural gas properties	$ 243,187,690	$ 164,419,619
Unevaluated oil and natural gas properties	15,490,704	5,044,584
Computer equipment and software	4,290,905	4,124,424
Other office property and equipment	1,990,676	1,682,854
Total property and equipment	264,959,975	175,271,481
Accumulated depletion, depreciation and amortization	(99,119,630)	(77,290,724)
Total property and equipment, net	$ 165,840,345	$ 97,980,757

The following table summarizes the cost of the properties not subject to amortization by the year the cost was incurred:

	December 31, 2004	December 31, 2003
Year cost incurred:		
1999	$ 193,060	$ 193,060
2000	8,611	8,611
2001	108,448	121,038
2002	143,856	319,188
2003	1,506,300	4,402,687
2004	13,530,429	--
Total	$ 15,490,704	$ 5,044,584

6. ACQUISITIONS AND DIVESTITURES

Contango Asset Acquisition

On December 29, 2004, the Company consummated the acquisition of interests in oil and natural gas properties located in south Texas from Contango Oil & Gas Company ("Contango"). The estimated final cash purchase price for the acquisition is $39.8 million. The cash purchase price at closing was $43.2 million, which was adjusted from the original price of $50.0 million for the results of operations between the July 1, 2004 effective date and October 31, 2004 pursuant to the closing adjustment provisions. At December 31, 2004 we have accrued a downward adjustment to the price of $3.4 million, representing the estimated results of operations between November 1, 2004 and the closing date December 29, 2004, that we anticipate realizing in March 2005 pursuant to the post-closing adjustment provisions. The purchase price was funded from the net proceeds of a public offering of common stock completed December 21, 2004 (see Note 11).

The following unaudited pro forma results for 2004, 2003 and 2002 show the effect on the Company's consolidated results of operations as if the Contango Asset Acquisition had occurred on January 1, 2002. They are the result of combining the statement of income of Edge with the statements of revenues and direct operating expenses for the properties adjusted for (1) the completion of the public offering of common stock to finance the cash purchase price, (2) assumption of ARO liabilities and accretion expense for the properties acquired, (3) depletion, depreciation and amortization expense applied to the adjusted basis of the properties acquired using the purchase method of accounting, and (3) the related income tax effects of these adjustments based on the applicable statutory rates. The statements of revenues and direct operating expenses for the Contango Assets exclude all other historical Contango expenses. As a result, certain estimates and judgments were made in preparing the pro forma adjustments, including as to the incremental expenses associated with the Contango Assets. The pro forma information includes numerous assumptions, and is not necessarily indicative of future results of operations:

	For the Year-Ended December 31, 2004	2003	2002
		(unaudited)	
	(In thousands, except per share amounts)		
Revenue	$ 89,941	$ 65,173	$ 50,082
Net income	$ 25,816	$ 17,203	$ 10,570
Net income per common share:			
Basic	$ 1.51	$ 1.25	$ 0.79
Diluted	$ 1.46	$ 1.23	$ 0.78

Miller Acquisition

On December 4, 2003, the Company completed its merger with Miller Exploration Company ("Miller"). The Company acquired 100 percent of the outstanding common stock of Miller in a stock for stock transaction pursuant to which Miller became a wholly-owned subsidiary of Edge. Under the terms of the merger agreement, each share of issued and outstanding common stock of Miller was converted into 1.22342 shares of Edge common stock. Edge issued approximately 2.6 million shares of Edge common stock to the shareholders of Miller in exchange for all of the outstanding common stock of Miller. The merger was treated as a tax-free reorganization and accounted for as a purchase business combination. Under this method of accounting, on the date of the merger, the assets and liabilities of Miller were recorded by Edge at their estimated fair market values.

The following unaudited pro forma results for 2003 and 2002 show the effect on the Company's consolidated results of operations as if the Miller transaction occurred on January 1, 2002. They are the result of combining the statement of income for Edge with the statement of income for Miller adjusted for (1) the revenue and costs associated with certain Alabama properties sold by Miller in June of 2003, prior to consummation of the merger, (2) depletion, depreciation and amortization expense of Miller applied to the adjusted basis of the properties acquired using the purchase method of accounting, and (3) the related income tax effects of these adjustments based on the applicable statutory rates. The pro forma data presented is based on numerous assumptions and is not necessarily indicative of future results of operations or comparable to actual 2004 results of the merged companies.

	For the Year-Ended December 31,	
	2003	2002
	(unaudited) (In thousands, except per share amounts)	
Revenue	$ 43,796	$ 30,676
Net income	7,339	171
Net income per common share:		
Basic	0.60	0.01
Diluted	0.59	0.01

Divestitures

During 2004, 2003 and 2002, the Company sold oil and gas properties for net proceeds of $60,000, $330,096, and $354,294, respectively. Proceeds from these dispositions were credited to the full cost pool. The Company's 2004 asset divestitures related primarily to the sale of certain oil and gas properties and equipment in Texas, Mississippi and Louisiana. The Company's 2003 asset divestitures related primarily to the sale of the Company's interest in affiliated entities, Essex I and II Joint Ventures, and certain oil and gas properties in Texas and Louisiana. The Company's 2002 divestitures were related to the sale of the Company's interest in certain oil and gas properties in Texas, Alabama, Montana and Louisiana.

7. ASSET RETIREMENT OBLIGATIONS

In June 2001, the FASB issued SFAS No. 143, which requires that an asset retirement obligation ("ARO") associated with the retirement of a tangible long-lived asset be recognized as a liability in the period in which it is incurred and becomes determinable. Under this method, when liabilities for dismantlement and abandonment costs, excluding salvage values, are initially recorded, the carrying amount of the related oil and gas properties is increased. The fair value of the ARO asset and liability is measured using expected future cash outflows discounted at the Company's credit-adjusted risk-free interest rate. Accretion of the liability is recognized each period using the interest method of allocation, and the capitalized cost is depleted over the useful life of the related asset.

The Company adopted SFAS No. 143 on January 1, 2003, which resulted in a net increase to oil and gas properties of $0.4 million and related liabilities of $0.9 million. These amounts reflect the ARO of the Company had the provisions of SFAS No. 143 been applied since inception and resulted in a non-cash charge to earnings of $357,825 ($550,500 pre-tax). Going forward the Company will record an abandonment liability associated with its oil and gas wells when those assets are placed in service. The changes to the ARO during the periods ended December 31, 2004 and 2003 are as follows:

	Year Ended December 31,			
	2004		2003	
ARO, beginning of year	$	1,811,995	$	942,736
Additional liabilities incurred		676,099		997,057
Liabilities settled		(397,974)		(85,164)
Accretion expense		98,968		66,625
Revisions		--		(109,259)
ARO, end of year	$	2,189,088	$	1,811,995
Current Portion	$	193,647	$	323,513
Long-term Portion	$	1,995,441	$	1,488,482

ARO liabilities incurred during the year ended December 31, 2004 include obligations assumed for 39 wells acquired in south Texas from Contango on December 29, 2004, as well as obligations for all successful wells drilled during the year. Liabilities settled during the year ended December 31, 2004 included 32 wells that were either plugged or sold.

The following table summarizes the pro forma net income and earnings per share for the year ended December 31, 2002 had SFAS 143 been adopted by the Company on January 1, 2002.

	For the Year Ended December 31, 2002			
	As Reported		Pro Forma	
Net income	$	749,745	$	715,192
Net income per share, basic	$	0.08	$	0.08
Net income per share, diluted	$	0.08	$	0.07

Had the Company applied the provisions of SFAS No. 143 in the previous periods, the pro forma amount of the ARO liability would have been $882,537 at January 1, 2002.

8. ACCRUED LIABILITIES

Below are the components of accrued liabilities as of December 31, 2004 and 2003:

	December 31,			
	2004		2003	
Accrued capital expenditures	$	4,653,450	$	4,751,882
Professional services		1,021,165		304,067
Salary and benefits		1,045,547		579,537
Royalties payable		4,451,094		3,283,521
Lease operating expenses including severance and ad valorem taxes payable		1,047,413		1,325,195
Other		846,818		1,211,834
Total Accrued Liabilities	$	13,065,487	$	11,456,036

9. HEDGING AND DERIVATIVE ACTIVITIES

Due to the volatility of oil and natural gas prices, the Company periodically enters into price-risk management transactions (e.g., swaps, collars and floors) for a portion of its oil and natural gas production to achieve a more predictable cash flow, as well as to reduce exposure from price fluctuations. While the use of these arrangements limits the Company's ability to benefit from increases in the price of oil and natural gas, it also reduces the Company's potential exposure to adverse price movements. The Company's arrangements, to the extent it enters into any, apply to only a portion of its production, provide only partial price protection against declines in oil and natural gas prices and limit the Company's potential gains from future increases in prices. None of these instruments are used for trading or speculative purposes. On a quarterly basis, the Company's management sets all of the Company's price-risk management policies, including volumes, types of instruments and counterparties. These policies are implemented by management through the execution of trades by the Chief Financial Officer after consultation and concurrence by the President and Chairman of the Board. The Board of Directors monitors the Company's policies and trades.

All of these price-risk management transactions are considered derivative instruments and accounted for in accordance with SFAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities"*. These derivative instruments are intended to hedge our price risk and may be considered hedges for economic purposes, but certain of these transactions may not qualify for cash flow hedge accounting. All derivative instrument contracts are recorded on the balance sheet at fair value. For those derivative instrument contracts that qualify for cash flow hedge accounting, the effective portion of the changes in the fair value of the contracts is recorded in other comprehensive income and the ineffective portion of the changes in the fair value of the contracts is recorded in revenue as they occur. While the contract is outstanding, the ineffective gain or loss may increase or decrease until settlement of the contract depending on the fair value at the measurement dates. When the hedged production is sold, the realized gains and losses on the contracts are removed from other comprehensive income and recorded in revenue. The Company is currently accounting for its natural gas contracts as cash flow hedges of future cash flows from the sale of natural gas. For those derivative instrument contracts that either do not qualify for cash flow hedge accounting or the Company does not designate as hedges of future cash flows, the changes in fair value are not deferred through other comprehensive income, but rather recorded in revenue immediately as unrealized gains or losses. The Company did not apply cash flow hedge accounting to its crude oil collars entered into in 2004, because although they were economic hedges, they did not qualify for hedge accounting.

For the year ended December 31, 2004, 2003 and 2002, the Company included in revenue realized and unrealized losses related to its natural gas hedges and oil derivatives. There was no ineffectiveness recognized during the years ended December 31, 2004, 2003 and 2002. The impact on total revenue from hedging activities for the three years ended December 31, 2004, 2003 and 2002 was as follows:

	Year Ended December 31,		
	2004	2003	2002
Natural gas hedging contract settlements	$ (328,500)	$ (4,455,590)	$ (326,950)
Crude oil derivative contract settlements	(880,765)	--	--
Hedge premium reclassification	(686,250)	--	--
Oil derivative contract unrealized change in fair value	(564,548)	--	--
Loss on hedging and derivatives	$ (2,460,063)	$ (4,455,590)	$ (326,950)

The outstanding hedges at December 31, 2004, 2003 and 2002 impacting the balance sheet were as follows:

Transaction Date	Transaction Type	Beginning	Ending	Price Per Unit	Volumes Per Day	Fair Value of Outstanding Hedging and Derivative Contracts as of December 31, 2004 (5)	2003
Natural Gas (1):							
12/03	Natural Gas Collar	01/01/2004	03/31/2004	$4.50-$7.05	5,000MMbtu	$ --	$ 37,688
08/03	Natural Gas Collar	(2) 01/01/2004	03/31/2004	$4.50-$7.00	10,000MMbtu	--	(91,504)
08/03	Natural Gas Collar	(2) 04/01/2004	09/30/2004	$4.50-$6.00	10,000MMbtu	--	42,996
08/03	Natural Gas Collar	(2) 10/01/2004	12/31/2004	$4.50-$7.00	10,000MMbtu	--	131,621
05/04	Natural Gas Collar	01/01/2005	03/31/2005	$5.00-$10.39	10,000MMbtu	92,703	--
07/04	Natural Gas Collar	04/01/2005	06/30/2005	$5.00-$7.53	10,000MMbtu	9,162	--
07/04	Natural Gas Collar	07/01/2005	09/30/2005	$5.00-$7.67	10,000MMbtu	(41,210)	--
10/04	Natural Gas Collar	01/01/2005	12/31/2005	$6.00-$9.52	10,000MMbtu	1,860,375	--
Crude Oil (3):							
03/04	Crude Oil Collar	04/01/2004	12/31/2004	$30.00-$35.50	400Bbl	(96,240)	--
05/04 (08/04) (4)	Crude Oil Collar	01/01/2005	12/31/2005	$35.00-$40.00	200/290Bbl	(468,308)	--
						$ 1,356,482	$ 120,801

1. The Company's current hedging activities for natural gas were entered into on a per MMbtu delivered price basis, using the Houston Ship Channel Index, with settlement for each calendar month occurring five business days following the expiration date.
2. This contract was entered into at a cost of $686,250.
3. Hedge accounting is not applied to the Company's collars on crude oil, which were entered into on a per barrel delivered price basis, using the West Texas Intermediate Index, with settlement for each calendar month occurring five business days following the expiration date. The change in fair value is reflected in net revenue for the year ended December 31, 2004.
4. In August 2004, the Company replaced the contract that was entered into May 2004 with a new contract that changes the volume and pricing terms. The put option is on 200 Bbl/D and the call option is on 290 Bbl/D. This transaction was completed at no additional cost to the Company.
5. The fair value of the Company's outstanding transactions is presented on the balance sheet by counterparty. Our counterparties net our positions with them, but we cannot present the net of the two counterparty positions because we do not have legal right of offset. Therefore one counterparty is presented in the Derivative Asset and one is presented in the Derivative Liability. The crude oil collar with a balance of ($468,308) is presented as a liability and the remaining contracts are presented as an asset. All contracts are considered current.

10. LONG-TERM DEBT

In March 2004, the Company entered into a new amended and restated credit facility (the "Credit Facility"), effective December 31, 2003, which permits borrowings up to the lesser of (i) the borrowing base and (ii) $100.0 million. Borrowings under the Credit Facility bear interest at a rate equal to prime plus 0.50% or LIBOR plus 2.25%. At December 31, 2004 the interest rate applied to our outstanding balance was 5.75%. As of December 31, 2004, $20.0 million in borrowings were outstanding under the Credit Facility. The Credit Facility matures December 31, 2006 and is secured by substantially all of the Company's assets.

Effective December 29, 2004, the Credit Facility's borrowing base was increased from $48.0 million to $65.0 million. The borrowing base under the Credit Facility was increased as a result of the Contango Asset Acquisition and our drilling activities since the last redetermination. The Company's available borrowing capacity under this facility was $45.0 million at December 31, 2004.

The Credit Facility provides for certain restrictions, including but not limited to, limitations on additional borrowings, sales of oil and natural gas properties or other collateral, and engaging in merger or consolidation transactions. The Credit Facility also prohibits dividends and certain distributions of cash or properties and certain liens. The Credit Facility also contains the following financial covenants, among others:

- The EBITDAX to Interest Expense ratio requires that the ratio of (a) consolidated EBITDAX (defined as EBITDA plus similar non-cash items and exploration and abandonment expenses for such period) of the Company for the four fiscal quarters then ended to (b) the consolidated interest expense of the Company for the four fiscal quarters then ended, not be less than 3.5 to 1.0.
- The Working Capital ratio requires that the amount of the Company's consolidated current assets less its consolidated current liabilities, as defined in the agreement, be at least $1.0 million. For the purposes of calculating the Working Capital ratio, current assets is adjusted for unused capacity under credit agreement and hedging and derivative assets and current liabilities is adjusted for derivative and hedging liabilities and asset retirement obligations.
- The Maximum Leverage ratio requires that the ratio, as of the last day of any fiscal quarter, of (a) Total Indebtedness (as defined in the Credit Facility) as of such fiscal quarter to (b) an amount equal to consolidated EBITDAX for the two quarters then ended times two, not be greater than 3.0 to 1.0.

Consolidated EBITDAX is a component of negotiated covenants with our lender and is presented here as part of the Company's disclosure of its covenant obligations.

11. SHELF REGISTRATION STATEMENT

The Company filed a $150 million shelf registration statement with the SEC, which became effective in May 2004. Under the shelf registration statement, the Company may issue, from time to time, any combination of debt securities, preferred stock, common stock or warrants for debt securities or equity securities in one or more offerings to those persons who agree to purchase our securities. Net proceeds, terms and pricing of the offering of securities issued under the shelf registration statement will be determined at the time of the offerings. The shelf registration statement does not provide assurance that the Company will or could sell any such securities. The Company's ability to utilize this shelf registration statement for the purpose of issuing, from time to time, any combination of debt securities, preferred stock, common stock or warrants for debt securities or equity securities will depend upon, among other things, market conditions and the existence of investors who wish to purchase the Company's securities at prices acceptable to the Company.

The Company completed an offering on December 21, 2004 of 3.5 million shares of its common stock under the Company's shelf registration statement, which generated net proceeds to us, before direct costs of the offering, of $47.8 million. These funds were used to finance the Contango Asset Acquisition preliminary adjusted purchase price of $43.2 million (see Note 6) and fund other general corporate purposes. On January 5, 2005, the underwriters exercised their over-allotment option for an additional 525,000 shares of common stock, which generated net proceeds to us of $7.2 million. These funds were used to reduce outstanding debt. Each of these sales was made under our shelf registration statement such that, at March 16, 2005, the Company had $91.8 million remaining for issuance under the shelf registration.

12. COMMITMENTS AND CONTINGENCIES

Commitments - At December 31, 2004, the Company was obligated under noncancelable operating leases. Following is a schedule of the remaining future minimum lease payments under these leases:

2005	$	629,200
2006		621,300
2007		621,300
2008		631,200
2009		622,400
Remainder		2,230,200
Total	$	5,355,600

Rent expense for the years ended December 31, 2004, 2003 and 2002 was approximately $474,300, 442,700, and $566,700, respectively.

Contingencies - From time to time the Company is a party to various legal proceedings arising in the ordinary course of business. While the outcome of lawsuits cannot be predicted with certainty, the Company is not currently a party to any proceeding that it believes, if determined in a manner adverse to the Company, could have a potential material adverse effect on its financial condition, results of operations or cash flows.

Additionally, the Company's operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stricter environmental legislation and regulations could continue. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes environmental protection requirements that result in increased costs to the oil and natural gas industry in general, the business and prospects of the Company could be adversely affected.

During the second quarter of 2004, the Company received notice that its franchise tax returns for the State of Texas would be audited for the tax years 1999 through 2002. After reviewing documents submitted, the agent representing the Office of the Comptroller of the State of Texas proposed adjustments to the calculation that would result in an increased franchise tax liability. The agent maintained that transfers by the parent company to its subsidiaries that the Company classified as intercompany loans should instead be classified as equity investments in the subsidiary. The State of Texas originally proposed that the franchise tax liability of the subsidiaries would be increased by approximately $3.0 million for the four-year period under audit.

During the third quarter of 2004 the agent reduced the proposed franchise tax deficiency adjustment to the Company and its subsidiaries to an aggregate of $467,000. The Company intends to vigorously contest this proposed franchise tax assessment through appropriate administrative levels in the Comptroller's Office. In the fourth quarter of 2004, there was an informal hearing at the local Comptroller's Office during which the agent indicated he would formally assess the proposed deficiency. The Company has not received any such deficiency assessment, but if it does, it intends to continue to vigorously contest the assessment through appropriate administrative levels in the Comptroller's Office and any other available means. Due to its intention to continue to vigorously contest the proposed adjustments, the Company has not recognized any provision for the additional franchise taxes that would result from the proposed deficiency.

13. SALES TO MAJOR CUSTOMERS AND OPERATORS

In accordance with Statement of Financial Accounting Standards No. 131 ("SFAS No. 131"), *Disclosures about Segments of an Enterprise and Related Information*, public business enterprises are required to report financial and other information about operating segments of the entity for which such information is available and is utilized by the chief operating decision maker. SFAS No. 131 also establishes standards for related disclosures about products and services, geographic area, and major customers. The Company operates as one business segment. We sold natural gas and crude oil production representing 10% or more of our total revenues for the years ended December 31, 2004, 2003, and 2002 as listed below:

	For the year ended December 31,		
Major Purchaser	**2004**	**2003**	**2002**
Upstream Energy Services (1)	22%	38%	24%
ChevronTexaco	22%	6%	18%
Copano Field Services	19%	16%	17%
BTA	2%	18%	5%
Southwestern Energy	1%	5%	15%

NOTE: Amounts disclosed are approximations and those that are less than 10% are presented for information and comparison purposes only. Also these percentages do not consider the effects of financial hedges.

(1) Upstream is an agent that sells our production to other purchasers on our behalf.

In the exploration, development and production business, production is normally sold to relatively few customers. A significant portion of our sales are made on our behalf by the operators of the properties and therefore these entities may be listed above. Substantially all of the Company's customers are concentrated in the oil and gas industry and revenue can be materially affected by current economic conditions and the price of certain commodities such as natural gas and crude oil, the cost of which is passed through to the customer. However, based on the current demand for natural gas and crude oil and the fact that alternate purchasers are readily available, we believe that the loss of any of our major purchasers would not have a long-term material adverse effect on our operations.

14. INCOME TAXES

Deferred income taxes reflect the tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts calculated for income tax purposes in accordance with SFAS No. 109. Significant components of the Company's deferred tax liabilities and assets as of December 31, 2004 and 2003 are as follows:

	December 31,	
	2004	**2003**
Deferred tax liability:		
Book basis of oil and natural gas properties in excess of tax basis	$ (28,874,455)	$ (12,479,467)
Deferred tax assets:		
Net operating loss carryforwards	25,857,283	17,548,865
Expenses not currently deductible for tax purposes	350,000	192,500
Accretion on ARO	130,563	95,924
Deferred compensation	572,304	531,479
Federal alternative minimum tax credits	75,000	75,000
Price risk management liability	(474,766)	201,976
Other	405,360	542,352
Total deferred tax asset	26,915,744	19,188,096
Net deferred tax asset (liability)	$ (1,958,711)	$ 6,708,629

Tax benefits of $462,020 and $137,141 for the year ended December 31, 2004 and 2003, respectively, are reflected as a component of equity. These tax benefits relate to the exercise of qualified stock options and the vesting of restricted stock at prices higher than those used for financial reporting purposes. Upon adoption of SFAS

No. 143 on January 1, 2003, the Company recorded a cumulative effect of change in accounting principle of $357,825, after taxes of $192,675.

The Company's provision (benefit) for income taxes consists of the following:

	2004	2003	2002
Current	$ --	$ --	$ --
Deferred	8,255,025	2,731,132	473,060
Total	$ 8,255,025	$ 2,731,132	$ 473,060

The differences between the statutory federal income taxes calculated using a federal tax rate of 35% and the Company's effective tax rate is summarized as follows:

	2004	2003	2002
Statutory federal income taxes	$ 8,184,496	$ 2,603,653	$ 427,982
Expenses not deductible for tax purposes and other	70,529	127,479	45,078
Income tax expense	$ 8,255,025	$ 2,731,132	$ 473,060

At December 31, 2004, the Company had cumulative net operating loss carryforwards ("NOLs") for federal income tax purposes of approximately $73.9 million that expire beginning 2007 through 2022. The Company believes that it is more likely than not that it will utilize all of these NOLs in connection with federal income taxes generated in the future. The estimated NOLs presented herein assume that certain items, primarily intangible drilling costs, have been written off for tax purposes in the current year. However, the Company has not made a final determination if an election will be made to capitalize all or part of these items for tax purposes in the future.

15. EMPLOYEE BENEFIT PLANS

Effective July 1, 1997, the Company established a defined-contribution 401(k) Savings & Profit Sharing Plan Trust (the "Plan") covering employees of the Company who are age 21 or older. The Company's matching contributions to the Plan are discretionary. For the years ended December 31, 2004, 2003 and 2002, the Company contributed approximately $121,300, $74,200, and $83,200, respectively, to the Plan.

16. EQUITY AND STOCK PLANS

Private Offering – In connection with a private offering on May 6, 1999 of 1,400,000 shares of common stock at a price of $5.40 per share the Company issued warrants for $0.125 per warrant, to acquire an additional 420,000 shares of common stock at $5.35 per share and were exercisable through May 6, 2004. All of these warrants have now been exercised. At the election of the Company, the warrants could have been called at a redemption price of $0.01 per warrant at any time after any date at which the average daily per share closing bid price for the immediately preceding 20 consecutive trading days exceeds $10.70. In November and December of 2003, 375,000 warrants were exercised for proceeds of approximately $2.0 million. In March 2004 Mr. Elias, our Chairman and Chief Executive Officer, exercised the remaining warrants, which resulted in the Company's issuance to him of 45,000 shares of common stock and net proceeds to us of $240,750.

Public Offering - In connection with a public offering on December 21, 2004, the Company issued 3,500,000 shares of common stock at a gross price of $14.45 per share. This offering generated net proceeds to us, after underwriter's fees and before direct costs of the offering, of $47.8 million. These shares were issued to generate funds to finance the Contango Asset Acquisition that was completed December 29, 2004.

Stock Plans - In conjunction with the Offering, the Company established the Incentive Plan of Edge Petroleum Corporation (the "Incentive Plan"). The Incentive Plan is discretionary and provides for the granting of awards, including options for the purchase of the Company's common stock and for the issuance of restricted and/or unrestricted common stock to directors, officers, employees and independent contractors of the Company. The options and restricted stock granted to date vest over periods of 2-3 years. The Company amended the Incentive Plan in December 2003, to increase the shares available under the plan from 1.2 million to 1.7 million. An aggregate of 1,700,000 shares of common stock have been reserved for grants under the Incentive Plan, of which 495,798 shares were available for future grants at December 31, 2004. The following nonqualified stock option awards and restricted stock grants were made under the Incentive Plan during each of the years indicated below:

	Number Granted	Market Value on Date of Grant
Options Awards:		
2004	13,000	$13.99
2003	32,000	$3.88 to $5.73
2002	175,800	$3.40 to $5.69
Restricted Stock Awards:		
2004	94,676	$10.09 to $16.89
2003	91,400	$3.88 to $6.80
2002	10,800	$5.01 to $5.18

Stock option awards vest 100 percent two years from date of grant. Shares of common stock associated with the restricted stock awards will be issued, subject to continued employment, ratably over three years in accordance with the award's vesting schedule, beginning on the first anniversary of the date of grant. Compensation expense from restricted stock is amortized over the vesting period and offset to additional paid in capital. Below is a summary of amortization of deferred compensation related to restricted stock awards for the years indicated:

Year Ended December 31,	Deferred Compensation Expense
2004	$ 498,372
2003	372,151
2002	399,249

Effective May 21, 1999, the Company amended and restated the Incentive Plan. In conjunction with those and other amendments of the Incentive Plan, the Company exchanged, on a voluntary basis, 556,488 outstanding nonqualified stock options of certain employees and Directors of the Company for 326,700 new common stock options in replacement of those options. The exercise price of the replacement options was $7.06 per share, which represents the fair market value on the date of grant. The replaced options have a ten-year term with 50% of the options vesting immediately on the date of grant with the remaining 50% vesting on May 21, 2000. On May 21, 1999, in conjunction with the repricing, the Company also issued 99,800 new ten-year common stock options to employees, which vested 100 percent on May 21, 2001. The exercise price of the new options was $7.06, which represents the fair market value on the date of grant. On June 1, 1999, the Company issued 21,000 ten-year common stock options to non-employee directors with an exercise price of $7.28 per share, which represented their fair market value at the date of grant, vesting 100 percent on June 1, 2001.

Deferred compensation cost reported in accordance with FIN 44 (see Note 2 above) included a charge for the year ended December 31, 2004. Below is a summary of FIN 44 charges related to the variable accounting for certain re-priced stock options impacting the Company's statement of operations for the years indicated:

Year Ended December 31,	Charge
2004	$ 1,135,628
2003	1,219,349
2002	3,385

As a component of his employment agreement with the Company, John Elias, CEO and Chairman of the Board, has been granted option awards and a restricted stock award outside of the Incentive Plan. Mr. Elias has also been granted some options and restricted stock under the Incentive Plan. The options vest and become exercisable over a two or three year period subsequent to issue. The restricted stock is issued ratably over three years in accordance with the award's vesting schedule, beginning on the first anniversary of the date of grant. Compensation expense is amortized over the vesting period and offset to additional paid in capital. The amortization of compensation expense related to this award was included in the amounts discussed above. Below is a summary of option and restricted stock grants to Mr. Elias made outside of the Incentive Plan:

Date Granted	Shares Outstanding	Exercise Price	Date Exercisable
Options (1):			
01/08/1999	200,000	$4.22	One-third upon issue and one-third upon each of January 1, 2000 and 2001
01/03/2000	50,000	$3.16	100% January 2002
01/03/2001	50,000	$8.88	100% January 2003
01/03/2002	50,000	$5.18	100% January 2004
04/02/2002	24,000	$5.59	100% April 2004
01/23/2003	50,000	$3.88	100% January 2005
04/01/2004	37,000	$13.99	100% January 2006
Restricted Stock (2):			
04/02/2001	14,000		Ratably over three years beginning on the first anniversary of the date of grant

(1) Exercise price equals the fair market value on the date of grant.
(2) Value was $7.75 per share, the market value on the date of grant.

A summary of the status of the Company's stock options and changes as of and for each of the three years ended December 31, 2004 is presented below:

	2004		2003		2002	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding, January 1	1,171,512	$8.76	1,098,050	$5.62	866,200	$5.62
Granted	50,000	$13.99	82,000	$4.35	273,800	$5.46
Assumed in merger	--	--	120,138	$39.76	--	--
Forfeited	(76,739)	$59.11	(24,000)	$6.04	(24,650)	$5.70
Exercised	(322,723)	$6.24	(104,676)	$4.07	(17,300)	$3.01
Outstanding, December 31	822,050	$5.91	1,171,512	$9.14	1,098,050	$5.62
Exercisable, December 31,	690,050	$5.51	843,412	$10.67	752,050	$5.34
Weighted average fair value of options granted during the period	$13.99		$3.23		$4.19	

A summary of the Company's stock options categorized by class of grant at December 31, 2004 is presented below:

All Options				Options Exercisable		
Range of Exercise Price	Shares Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Range of Exercise Price	Shares Outstanding	Weighted Average Exercise Price
$3.00 - $3.88	141,700	6.38	$3.44	$3.00 - $3.16	80,700	$3.12
$4.22	200,000	4.01	$4.22	$4.22	200,000	$4.22
$5.18 - $5.73	199,900	7.32	$5.49	$5.18-$5.69	178,900	$5.46
$7.06 - $7.58	180,350	4.52	$7.11	$7.06 - $7.58	180,350	$7.11
$8.88	50,000	6.01	$8.88	$8.88	50,000	$8.88
$13.50-$13.99	50,100	9.24	$13.99	$13.50	100	$13.50

Computation of Earnings per Share - The following is presented as a reconciliation of the numerators and denominators of basic and diluted earnings per share computations, in accordance with SFAS No. 128.

	Year Ended December 31, 2004		
	Income (Numerator)	Shares (Denominator)	Per Share Amount
Basic EPS			
Income available to common stockholders	$ 15,129,250	13,029,075	$ 1.16
Effect of Dilutive Securities			
Common stock options	--	476,823	(0.04)
Restricted stock	--	142,363	(0.01)
Diluted EPS			
Income available to common stockholders	$ 15,129,250	13,648,261	$ 1.11

	Year Ended December 31, 2003		
	Income (Numerator)	Shares (Denominator)	Per Share Amount
Basic EPS			
Income available to common stockholders	$ 4,350,050	9,726,140	$ 0.45
Effect of Dilutive Securities			
Common stock options	--	148,618	(0.01)
Restricted stock	--	110,379	--
Warrants	--	2,414	--
Diluted EPS			
Income available to common stockholders	$ 4,350,050	9,987,551	$ 0.44

	Year Ended December 31, 2002		
	Income (Numerator)	Shares (Denominator)	Per Share Amount
Basic EPS			
Income available to common stockholders	$ 749,745	9,384,097	$ 0.08
Effect of Dilutive Securities			
Common stock options	--	85,633	--
Restricted stock	--	135,841	--
Diluted EPS			
Income available to common stockholders	$ 749,745	9,605,571	$ 0.08

17. RELATED PARTY TRANSACTIONS

The transactions described below were carried out on terms at least as favorable to the Company as could have been obtained from unaffiliated third parties in arm's length negotiations, however, because the transactions were with affiliates, it is possible that the Company would have obtained different terms from a truly unaffiliated third-party.

Affiliates' Ownership in Prospects – Edge Group Partnership, Edge Holding Company, L.P., a limited partnership of which Mr. Sfondrini and a corporation wholly owned by him are the general partners, Andex Energy Corporation and Texedge Energy Corporation, corporations of which Mr. Andrews is an officer and members of his immediate family hold ownership interests, Mr. Raphael, Jovin, L.P. (a limited partnership, the general partners of which are a company wholly owned by Mr. Sfondrini and a company of which Mr. Andrews is an officer) and Essex II Joint Venture, own certain working interests in the Company's Nita and Austin Prospects and certain other wells and prospects operated by the Company. These working interests aggregate 7.19% in the Austin Prospect, 6.27% in the Nita Prospect and are neglible in other wells and prospects. These working interests bear their share of lease operating costs and royalty burdens on the same basis as the Company. In addition, Bamaedge, L.P., a limited partnership of which Andex Energy Corporation is the general partner, and Mr. Raphael also hold overriding royalty interests with respect to the Company's working interest in certain wells and prospects. Neither Mr. Raphael nor Bamaedge L.P. has an overriding interest in excess of 0.075% in any one well or prospect. Essex I Joint Venture and Essex II Joint Venture (a joint venture of which Mr. Sfondrini and a company wholly owned by him are the managers) own royalty and overriding royalty interests in various wells operated by the Company. The combined royalty and overriding royalty interests of the Essex I and Essex II Joint Ventures do not exceed 6.2% in any one well or prospect. The gross amounts paid or accrued to these persons and entities by the Company in 2004 (including net revenue, royalty and overriding royalty interests) and the amounts these same persons and entities paid to the Company for their respective share of lease operating expenses and other costs is set forth in the following table:

Owner	Total Amounts Paid by the Company to Owners in 2004 including Overriding Royalty (1)	Lease Operating Expenses paid to the Company by Owners in 2004
Andex Corporation /Texedge Corporation	$ 3,896	$ 2,578
Bamaedge, L.P.	3,594	--
Edge Group Partnership	387,603	40,284
Edge Holding Co., L.P.	71,177	7,065
Essex I Royalty Joint Venture	32,603	--
Essex II Royalty Joint Venture	150,509	5,629
Jovin, L.P.	--	--
Stanley Raphael	5,209	412
Total	$ 654,591	$ 55,968

(1) In the case of Essex I and II Royalty Joint Ventures, amount includes royalty income in addition to working interest and overriding royalty income. The Company sold its interest in these entities in 2003, but Mr. Sfondrini, a Director, maintains an indirect interest in these entities.

18. SUPPLEMENTAL DISCLOSURE OF NON-CASH INVESTING AND FINANCING ACTIVITIES

A summary of non-cash investing and financing activities for the years ended December 31, 2004, 2003 and 2002 is presented below:

Description	Number of shares issued	Fair Market Value
2004:		
Shares issued to satisfy restricted stock grants	70,463	$ 446,881
Shares issued to fund the Company's matching contribution under the Company's 401 (k) plan	7,500	$ 111,797
2003:		
Shares issued to satisfy restricted stock grants	75,095	$ 395,192
Shares issued to fund the Company's matching contribution under the Company's 401 (k) plan	14,475	$ 69,375
Shares issued in Miller merger	2,604,757	$ 14,421,051
2002:		
Shares issued to satisfy restricted stock grants	76,337	$ 409,777
Shares issued to fund the Company's matching contribution under the Company's 401 (k) plan	17,538	$ 70,513

Supplemental Disclosure of Cash Flow Information

	For the Year Ended December 31,		
	2004	2003	2002
Cash paid during the period for:			
Interest, net of amounts capitalized	$ 331,399	$ 678,805	$ 15,582
Federal alternative minimum tax payments	--	--	--

19. SUPPLEMENTAL FINANCIAL QUARTERLY RESULTS (unaudited):

The sum of the individual quarterly basic and diluted earnings (loss) per share amounts may not agree with year-to-date basic and diluted earnings (loss) per share amounts as a result of each period's computation being based on the weighted average number of common shares outstanding during that period.

	Fourth Quarter	Third Quarter RESTATED (1)	Second Quarter	First Quarter
	(in thousands, except per share amounts)			
2004:				
Oil and natural gas revenue	$ 19,601	$ 13,242	$ 15,847	$ 15,815
Operating expenses	11,293	9,035	9,755	10,601
Operating income	8,308	4,207	6,092	5,214
Other expense, net	(105)	(50)	(142)	(140)
Income tax expense	(2,896)	(1,474)	(2,094)	(1,791)
Net income	$ 5,307	$ 2,683	$ 3,856	$ 3,283
Basic earnings per share	$ 0.39	$ 0.21	$ 0.30	$ 0.26
Diluted earnings per share	$ 0.38	$ 0.20	$ 0.28	$ 0.25
2003:				
Oil and natural gas revenue	$ 10,198	$ 8,895	$ 7,994	$ 6,839
Operating expenses	9,030	6,137	5,453	5,205
Operating income	1,168	2,758	2,541	1,634
Other expense, net	(206)	(120)	(162)	(174)
Income tax expense	(418)	(946)	(845)	(522)
Net income before cumulative effect of accounting change	544	1,692	1,534	938
Cumulative effect of accounting change	--	--	--	(358)
Net income	$ 544	$ 1,692	$ 1,534	$ 580
Basic earnings per share	$ 0.05	$ 0.18	$ 0.16	$ 0.06
Diluted earnings per share	$ 0.05	$ 0.17	$ 0.16	$ 0.06

(1) The Company recently discovered an error in a consolidating financial statements spreadsheet application used to eliminate intercompany balances. Amounts accumulated in the property account for one subsidiary were also included as an accrued capital expenditure by another subsidiary and inadvertently not eliminated in consolidation. The Company has filed Amendment No. 1 to its Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2004 to restate the financial statements and other disclosures therein to correct such error. The amounts set forth above as of and for September 30, 2004 reflect the restated amounts. No other interim or annual financial statements included in any other Quarterly Report on Form 10-Q or Form 10-K of the Company were required to be restated. The principal changes effected by the restatement are set forth below in the following reconciliation:

(2)

	Third Quarter REPORTED	Third Quarter ADJUSTMENTS	Third Quarter RESTATED
2004			
Oil and natural gas revenue	$ 13,242	$ --	$ 13,242
Operating expenses	9,348	(313)	9,035
Operating income	3,894	313	4,207
Other expense, net	(50)	--	(50)
Income tax expense	(1,355)	(119)	(1,474)
Net income	$ 2,490	$ 193	$ 2,683
Basic earnings per share	$ 0.19	$ 0.02	$ 0.21
Diluted earnings per share	$ 0.18	$ 0.02	$ 0.20

Management has concluded, based on the circumstances involving the spreadsheet error discussed above, that as of December 31, 2004, a material weakness in internal control over financial reporting existed with respect to the design of the Company's controls over the elimination of intercompany balance and transactions. See *ITEM 9A. "CONTROLS AND PROCEDURES."*

20. SUPPLEMENTARY FINANCIAL INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (unaudited)

This footnote provides unaudited information required by SFAS No. 69, "*Disclosures About Oil and Natural Gas Producing Activities.*" The Company's oil and natural gas properties are located within the United States of America, which constitutes one cost center.

Capitalized Costs - Capitalized costs and accumulated depletion, depreciation and amortization relating to the Company's oil and natural gas producing activities, all of which are conducted within the continental United States, are summarized below:

	December 31, 2004	December 31, 2003
Developed oil and natural gas properties	$ 243,187,690	$ 164,419,619
Unevaluated oil and natural gas properties	15,490,704	5,044,584
Accumulated depletion, depreciation and amortization	(93,639,018)	(72,167,411)
Net capitalized cost	$ 165,039,376	$ 97,296,792

Costs Incurred - Costs incurred in oil and natural gas property acquisition, exploration and development activities are summarized below:

	Year Ended December 31,		
	2004	2003	2002
Acquisition cost:			
Unproved properties	$ 12,162,649	$ 6,052,137	$ 5,465,794
Proved properties	33,980,135	10,373,529	1,369,464
Exploration costs	8,297,370	6,016,951	4,725,032
Development costs	34,548,410	12,271,471	7,926,579
Subtotal	88,988,564	34,714,088	19,486,869
Asset retirement costs (1)	278,125	897,512	--
Total costs incurred	$ 89,266,689	$ 35,611,600	$ 19,486,869

(1) Excluded from asset retirement costs in 2003 was $640,400 related to the cumulative effect of the adoption of SFAS No. 143 on January 1, 2003 (See Note 7).

Net costs incurred excludes sales of proved oil and natural gas properties which are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves.

Results of Operations - Results of operations for the Company's oil and natural gas producing activities are summarized below:

	Year Ended December 31,		
	2004	2003	2002
Oil and natural gas revenue	$ 64,505,348	$ 33,926,007	$ 20,911,294
Operating expenses:			
Oil and natural gas operating expenses and ad valorem taxes	5,356,246	3,109,392	2,628,320
Production taxes	3,952,524	2,006,402	1,203,270
Accretion expense (1)	98,968	66,625	--
Depletion expense	21,471,606	12,906,956	9,697,144
Results of operations from oil and gas producing activities	$ 33,626,004	$ 15,836,632	$ 7,382,560

(1) The Company adopted SFAS No. 143 effective January 1, 2003 using a cumulative effect approach, therefore no comparable accretion expense appears 2002 (See Note 7).

Reserves - Proved reserves are estimated quantities of oil and natural gas, which 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 reasonably be expected to be recovered through existing wells with existing equipment and operating methods. Proved oil and natural gas reserve quantities and the related discounted future net cash flows before income taxes (see Standardized Measure) for the periods presented are based on estimates prepared by Ryder Scott Company and W.D. Von Gonten & Co., independent petroleum engineers. Such estimates have been prepared in accordance with guidelines established by the SEC.

The Company's net ownership in estimated quantities of proved oil and natural gas reserves and changes in net proved reserves, all of which are located in the continental United States, are summarized below.

	Natural Gas (Mcf) Year Ended December 31,		
	2004	2003	2002
Proved developed and undeveloped reserves			
Beginning of year	46,824,000	34,980,000	38,934,000
Revisions of previous estimates	(5,993,260)	(486,143)	(5,579,800)
Purchase of oil and gas properties	14,803,000	8,437,000	521,300
Extensions and discoveries	19,825,551	10,248,298	6,376,900
Sales of natural gas properties	--	(65,100)	(6,000)
Production	(9,148,191)	(6,290,055)	(5,266,400)
End of year	66,311,100	46,824,000	34,980,000
Proved developed reserves at year end	50,698,000	36,938,000	24,234,000

	Oil, Condensate and Natural Gas Liquids (Bbls) Year Ended December 31,		
	2004	2003	2002
Proved developed and undeveloped reserves			
Beginning of year	2,851,072	2,342,315	978,361
Revisions of previous estimates	(106,133)	(46,348)	1,090,845
Purchase of oil and gas properties	267,354	387,743	62,939
Extensions and discoveries	1,270,134	472,904	491,519
Sales of natural gas properties	--	(5,058)	(521)
Production	(490,801)	(300,484)	(280,828)
End of year	3,791,626	2,851,072	2,342,315
Proved developed reserves at year end	2,698,125	2,104,610	1,509,950

Standardized Measure - The Standardized Measure of Discounted Future Net Cash Flows relating to the Company's ownership interests in proved oil and natural gas reserves for each of the three years ended December 31, 2004 is shown below:

	Year Ended December 31,		
	2004	2003	2002
Future cash inflows	$ 521,262,763	$ 350,187,406	$ 212,064,453
Future oil and natural gas operating expenses	(118,492,193)	(75,208,036)	(33,151,831)
Future development costs	(31,794,903)	(13,203,914)	(8,069,700)
Future income tax expense	(75,094,884)	(53,902,855)	(36,475,435)
Future net cash flows	295,880,783	207,872,601	134,367,487
10% discount factor	(79,009,770)	(55,705,257)	(36,811,015)
Standardized measure of discounted future net cash flows	$ 216,871,013	$ 152,167,344	$ 97,556,472

Future cash flows are computed by applying year-end prices of oil and natural gas to year-end quantities of proved oil and natural gas reserves. Future oil and natural gas operating expenses and development costs are computed primarily by the Company's internal petroleum engineers and are provided to external independent petroleum engineers as estimates of expenditures to be incurred in developing and producing the Company's proved oil and natural gas reserves at the end of the year, based on year-end costs and assuming the continuation of existing economic conditions.

Future income taxes are based on year-end statutory rates, adjusted for net operating loss carryforwards and tax credits. A discount factor of 10% was used to reflect the timing of future net cash flows. The Standardized Measure of Discounted Future Net Cash Flows is not intended to represent the replacement cost or fair market value of the Company's oil and natural gas properties.

The Standardized Measure of Discounted Future Net Cash Flows does not purport, nor should it be interpreted, to present the fair value of the Company's oil and natural gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

Changes in Standardized Measure - Changes in Standardized Measure of Discounted Future Net Cash Flows relating to proved oil and gas reserves are summarized below:

	Year Ended December 31,		
	2004	**2003**	**2002**
Changes due to current year operations:			
Sales of oil and natural gas, net of oil and natural gas operating expenses	$ (56,968,998)	$ (33,393,818)	$ (17,079,705)
Sales of oil and natural gas properties	--	(356,195)	(5,629)
Purchase of oil and gas properties	65,402,748	28,079,806	1,402,730
Extensions and discoveries	65,466,396	33,535,443	15,519,251
Changes due to revisions of standardized variables:			
Prices and operating expenses	17,648,293	32,213,734	38,029,737
Revisions of previous quantity estimates	(21,190,007)	(2,395,449)	2,378,838
Estimated future development costs	(15,961,730)	(2,295,084)	(20,172)
Income taxes	(9,189,919)	(7,585,409)	(11,143,442)
Accretion of discount	15,216,734	9,755,647	6,328,285
Production rates (timing) and other	4,280,152	(2,947,803)	(1,136,268)
Net change	64,703,669	54,610,872	34,273,625
Beginning of year	152,167,344	97,556,472	63,282,847
End of year	$ 216,871,013	$ 152,167,344	$ 97,556,472

Sales of oil and natural gas, net of oil and natural gas operating expenses are based on historical pre-tax results. Sales of oil and natural gas properties, extensions and discoveries, purchases of minerals in place and the changes due to revisions in standardized variables are reported on a pre-tax discounted basis, while the accretion of discount is presented on an after tax basis.

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March 24, 2005

Dear Stockholder:

You are cordially invited to attend the annual meeting of stockholders of Edge Petroleum Corporation to be held at the Doubletree Hotel, 400 Dallas Street, Houston, Texas 77002, on Wednesday, April 27, 2005 at 10:00 a.m. Houston time.

This booklet includes the notice of the meeting and the Proxy Statement, which contains information about the Board and its committees and personal information about each of the nominees for the Board. Other matters on which action is expected to be taken during the meeting are also described.

If you plan to attend the meeting in person, please follow the advance registration instructions in the back of this Proxy Statement which will expedite your admission to the meeting. Whether or not you plan to attend the annual meeting in person, it is important that you complete, sign, date and promptly return the enclosed proxy card or that you give your proxy by telephone or the Internet. To vote by phone or the Internet, please follow the instructions on your proxy card.

It is important that your shares are represented at the meeting, whether or not you are able to attend personally. Accordingly, we urge you to vote your shares at your earliest convenience.

Our Board and employees mourn the death of Joe Musolino, a good friend and valued director of the Company, who passed away on March 20th of this year. On behalf of the Company and our stockholders, we extend our deepest sympathies to his wife, Kathy, and his entire family. Mr. Musolino faithfully served for three years on the Company's Board of Directors. He was a member of the Audit Committee and the chairman of the Corporate Governance/ Nominating Committee. Mr. Musolino served as an advisory director of First American Bank, SSB. He also served on the boards of Bank of America, as well as Pool Energy Services Company and Justin Industries. His philanthropic activities included serving as chairman of the Greater Houston Partnership, chairman of the Dallas United Way, chairman of Baylor University Medical Center Foundation and a director of various other civic and professional organizations. Joe was a graduate of the University of Oklahoma and served his country in the U.S. Navy. He will be greatly missed.

On behalf of the Board of Directors, thank you for your continued support of the Company. I look forward to greeting as many of our stockholders as possible at the annual meeting.

/s/ John W. Elias

JOHN W. ELIAS
Chairman of the Board, President
and Chief Executive Officer

PROXY STATEMENT

This Proxy Statement and the accompanying proxy card are being mailed to stockholders beginning on or about March 24, 2005. They are furnished in connection with the solicitation by the Board of Directors of Edge Petroleum Corporation (the "Company") of proxies from the holders of the Company's common stock, par value $0.01 per share ("Common Stock"), for use at the 2005 annual meeting of stockholders (the "Annual Meeting") to be held at the time and place and for the purposes set forth in the accompanying notice. In addition to the solicitation of proxies by mail, proxies may also be solicited by telephone, telegram or personal interview by regular employees of the Company. The Company will pay all costs of soliciting proxies. The Company will also reimburse brokers or other persons holding stock in their names or in the names of their nominees for their reasonable expenses in forwarding proxy material to beneficial owners of such stock.

All duly executed proxies received prior to the meeting will be voted in accordance with the choices specified thereon. As to any matter for which no choice has been specified in a duly executed proxy, the shares represented thereby will be voted **FOR** the election as a director of the nominee listed herein, **FOR** the approval of the proposed amendment to the Company's Restated Certificate of Incorporation to increase the number of authorized shares of Common Stock from 25 million to 60 million, **FOR** approval of the appointment of BDO Seidman, LLP as the Company's independent registered public accounting firm for 2005 and at the discretion of the persons named in the proxy in connection with any other business that may properly come before the Annual Meeting. See "Other Business" on page 22 for information concerning the voting of proxies if other matters are properly brought before the Annual Meeting. A stockholder giving a proxy may revoke it at any time before it is voted at the Annual Meeting by filing with the Corporate Secretary an instrument revoking it, by delivering a duly executed proxy bearing a later date or by appearing at the Annual Meeting and voting in person.

As of March 17, 2005, the record date for determining stockholders entitled to vote at the Annual Meeting, the Company had outstanding and entitled to vote **17,100,555** shares of Common Stock. The Common Stock is the only class of stock of the Company outstanding at the record date and entitled to vote at the Annual Meeting. Each share entitles the holder to one vote on each matter submitted to a vote of stockholders. Cumulative voting is not permitted. The requirement for a quorum at the Annual Meeting is the presence in person or by proxy of holders of a majority of the outstanding shares of Common Stock.

In addition to voting in person at the Annual Meeting, stockholders of record may vote by proxy by calling a toll-free phone number, by using the Internet or by mailing their signed proxy cards. The telephone and Internet voting procedures are designed to authenticate stockholders' identity, to allow stockholders to give their voting instructions and to confirm that stockholders' instructions have been recorded properly. Specific instructions for stockholders of record who wish to use the telephone or Internet voting procedures are set forth on the enclosed proxy card.

If your shares are held in the name of a bank, broker or other holder of record, you will receive instructions from the holder of record that you must follow in order for your shares to be voted. Certain of these institutions offer telephone and Internet voting.

A broker non-vote occurs when a broker submits a proxy card with respect to shares of common stock held in a fiduciary capacity (typically referred to as being held in "street name"), but declines to vote on a particular matter because the broker has not received voting instructions from the beneficial owner. Abstentions, shares with respect to which authority is withheld and broker non-votes that are voted on any matter are included in determining whether a quorum is present. Abstentions are treated as shares that are present and entitled to vote for purposes of determining the outcome of any matter submitted to the stockholders for a vote. Abstentions, however, do not constitute a vote "for" or "against" any matter and thus will be disregarded in the calculation of a plurality of "votes cast". Under the rules that govern brokers who are voting with respect to shares held in street name, brokers have the discretion to vote such shares on routine matters, but not on non-routine matters. Routine matters include the election of directors, increases in authorized common stock and ratification of auditors. Votes are counted, and the count is certified, by an inspector of elections. Information regarding the vote required for approval of particular matters is set forth in the discussion of those matters appearing elsewhere in this Proxy Statement.

The Annual Report to Stockholders, which includes financial statements of the Company for the year ended December 31, 2004, has been mailed to all stockholders entitled to vote at the Annual Meeting on or before the date of mailing this Proxy Statement. The Securities and Exchange Commission ("SEC") permits a single set of annual reports and proxy statements to be sent to any household at which two or more stockholders reside if they appear to be members of the same family. Each stockholder continues to receive a separate proxy card. This procedure, referred to as householding, reduces the volume of duplicate information stockholders receive and reduces mailing and printing expenses. A number of brokerage firms have instituted householding.

As a result, if you hold your shares through a broker and you reside at an address at which two or more stockholders reside, you will likely be receiving only one annual report and proxy statement unless any stockholder at that address has given the broker contrary instructions. However, if any such beneficial stockholder residing at such an address wishes to receive a separate annual report or proxy statement in the future, that stockholder should contact their broker or send a request to the Company's corporate secretary at the Company's principal executive offices, 1301 Travis, Suite 2000, Houston, Texas 77002, telephone number (713) 654-8960. The Company will deliver, promptly upon written or oral request to the corporate secretary, a separate copy of the 2004 Annual Report and this Proxy Statement to a beneficial stockholder at a shared address to which a single copy of the documents was delivered. The Annual Report is not a part of the proxy solicitation material.

Attendance at the annual meeting is limited to the Company's stockholders or their designated representative or proxy, members of their immediate family and the Company's employees and guests. In order to attend as a stockholder or immediate family member, you or your family member must be a stockholder of record as of March 17, 2005, or you must provide a copy of a brokerage statement or other evidence of beneficial ownership showing ownership of common stock on March 17, 2005. If you or your designated representative or proxy plan to attend the meeting, please follow the advance registration instructions in the back of this Proxy Statement which will expedite your admission to the meeting.

PROPOSAL I

Election of Director

The Company's Board of Directors is divided into three classes, with staggered terms of office. The term for each class expires on the date of the third annual stockholders' meeting for the election of directors following the most recent election of directors for such class. Each director holds office until the next annual meeting of stockholders for the election of directors of his class and until his successor has been duly elected and qualified.

One director is to be elected to the class of directors whose current term will end in 2005. The name of Mr. Vincent S. Andrews will be placed in nomination, and the persons named in the proxy will vote in favor of such nominee unless authority to vote in the election of director is withheld. Mr. Andrews is currently a director of the Company. Joseph R. Musolino, who had served as a director of the Company since May 2002, passed away on March 20, 2005. He had been nominated for reelection as a director at the Annual Meeting. In addition to his service to the Company, he was the retired Vice Chairman, Texas, of Bank of America, N.A., and its corporate predecessors, and served as an advisory director of First American Bank, SSB. Mr. Musolino was also a member of the Audit and Corporate Governance/Nominating (chairman) Committees of the Board. Mr. Musolino was a good friend and valued director who served our Company faithfully. He will be greatly missed.

The persons named in the proxy may act with discretionary authority in the event the nominee should become unavailable for election, although management is not currently aware of any circumstances likely to result in such nominee becoming unavailable for election. In accordance with the Company's Bylaws, the director will be elected by a plurality of the votes cast; accordingly, abstentions and broker non-votes will have no effect. A stockholder may, in the manner set forth in the enclosed proxy card, instruct the proxy holder not to vote that stockholder's shares for the named nominee.

Nominee — The following summary sets forth information concerning the nominee for election as a director at the Annual Meeting, including such nominee's age, position with the Company, if any, and business experience during the past five years.

Vincent S. Andrews has served as a director of the Company since December 1996 and served as a director of the Company's corporate predecessor from April 1991 until the Company's initial public offering in March 1997 (the "Offering"). Mr. Andrews has been an active investor in the Company's corporate predecessor since 1988. Mr. Andrews has, for more than five years, served as president of Vincent Andrews Management Corporation, a privately held management company primarily involved in personal financial management. Mr. Andrews is a member of the Audit Committee of the Board. He is 64 years old.

The Board of Directors recommends that stockholders vote FOR the election of Mr. Andrews as a director of the Company whose term will expire in 2008.

Directors with Terms Expiring in 2006 and 2007 — The following summaries set forth information concerning six directors of the Company whose present terms of office will continue until 2006 or 2007, including each director's age, position with the Company, if any, and business experience during the past five years.

Thurmon M. Andress has served as a director of the Company since November 2002. For the past five years he has been the president of Andress Oil & Gas Company, a private company located in Houston, Texas, engaged in the business of oil and gas exploration and development. He also serves as the managing director-Houston of Breitburn Energy Company LLC, a private company headquartered in Los Angeles, California, engaged in oil and gas production with operations primarily in California. Mr. Andress has over 40 years experience in the oil and gas industry. He is the chairman of the Compensation Committee. He is 71 years old. Mr. Andress' current term as a director expires in 2006.

John W. Elias has served as the Chief Executive Officer and Chairman of the Board of the Company since November 1998 and as President since January 2000. From April 1993 to September 1998, he served in various senior management positions, including Executive Vice President of Seagull Energy Corporation, a company engaged in oil and gas exploration, development and production and pipeline marketing. Prior to April 1993, Mr. Elias served in various positions for more than 30 years, including senior management positions with Amoco Corporation, a major integrated oil and gas company. Mr. Elias has more than 40 years of experience in the oil and natural gas exploration and production business. He is 64 years old. Mr. Elias' current term as a director expires in 2006.

John Sfondrini has served as a director of the Company since December 1996 and prior to that as director of the Company's corporate predecessors from 1986, when he arranged for the capitalization of a predecessor partnership. For more than five years, he has been self-employed as a consultant that assists his clients in raising and investing private capital for growth-oriented companies in multiple industry segments, including oil and gas. Mr. Sfondrini is a member of the Corporate Governance/Nominating Committee of the Board. He is 56 years old. Mr. Sfondrini's current term as a director expires in 2006.

Stanley S. Raphael has served as a director of the Company since December 1996 and prior to that served as a director of the Company's corporate predecessor from April 1991 until the Offering. For more than five years, Mr. Raphael has been primarily engaged as a management consultant and is presently the sole owner and director of Trade Consultants, Inc., a management consulting firm. He is also a director and the retired Chairman of American Polymers Inc., a polystyrene manufacturer and plastics distributor. Previously, he was active in trading crude oil, petroleum products, LPG, petrochemicals, and plastics worldwide. Mr. Raphael is a member of the Corporate Governance/Nominating Committee of the Board. He is 69 years old. Mr. Raphael's current term as a director expires in 2007.

Robert W. Shower has served as a director of the Company since March 1997. From December 1993 until his retirement in April 1996, Mr. Shower served as Executive Vice President and Chief Financial Officer of Seagull Energy Corporation, a company engaged in oil and gas exploration, development and production and pipeline marketing. From March 1992 to December 1993, he served as such company's Senior Vice President and Chief Financial Officer. Until May 2002, Mr. Shower served as a director of Lear Corporation and Nuevo Energy Company. Mr. Shower is a member of the Compensation and Audit (chairman) Committees of the Board. He is 67 years old. Mr. Shower's current term as a director expires in 2007.

David F. Work has served as a director of the Company since November 2002. For more than five years prior to October 2000, he served in various management capacities with BP Amoco and BP, including North American vice president of BP. Since his retirement from BP in 2000 and until October 2003, he served as the chairman of Energy Virtual Partners, Inc., a private company engaged in the business of managing under-resourced oil and gas properties. Mr. Work is a member of the Compensation and Corporate Governance/Nominating Committees of the Board. He is 60 years old. Mr. Work's current term as a director expires in 2007.

There are no family relations, of first cousin or closer, among the Company's directors or executive officers by blood, marriage or adoption. The Board had determined that all directors of the Company are independent directors within the meaning of Marketplace Rule 4200(a)(15) of the Nasdaq Stock Market, except that Mr. Elias is not independent because he is an employee of the Company. While Mr. Sfondrini has a number of relationships and he or his affiliates are parties to certain transactions that could be viewed as transactions involving the Company, as described under "Certain Transactions" later in this Proxy Statement, the Board does not view these relationships and transactions as precluding a finding of his independence under the Nasdaq requirements.

Standing Committees, Board Organization, Director Nominations and Meetings

Compensation Committee. The members of the Compensation Committee of the Board are Messrs. Andress (chairman), Shower and Work, each of whom has been determined to be independent within the meaning of Marketplace Rule 4200(a)(15) of the Nasdaq Stock Market. The Board of Directors adopted a charter for the Compensation Committee effective January 1, 2004 (the "Compensation Committee Charter"). The duties and functions performed by the Compensation Committee are (a) to review and recommend to the Board of Directors or determine the annual salary, bonus, stock options and other benefits, direct and indirect, of the executive officers; (b) to review new executive compensation programs, review on a periodic basis the operation of the Company's executive compensation programs to determine whether they are properly coordinated, establish and periodically review policies for the administration of executive compensation programs, and take steps, consistent with the contractual obligations of the Company, to modify any executive compensation programs that yield payments and benefits that are not reasonably related to executive performance; (c) to establish and periodically review policies in the area of management perquisites; and (d) to exercise all of the powers of the Board of Directors with respect to any other matters involving the compensation of employees and the employee benefits of the Company as may be delegated to the Compensation Committee from time to time.

Audit Committee. The members of the Audit Committee of the Board are Messrs. Andrews and Shower (chairman). In addition, Mr. Musolino served as a member of the Audit Committee until his recent death on March 20, 2005. Each of Messrs. Andrews, Shower and Musolino has been determined to be independent within the meaning of Marketplace Rules 4200(a)(15) and 4350(d)(2)(A) of the Nasdaq Stock Market. On March 22, 2005, the Company notified the Nasdaq Stock Market of the death of Mr. Musolino. The Company further advised Nasdaq that as a result of Mr. Musolino's death, the Company is not in compliance with the audit committee composition requirement set forth in Rule 4350(d)(2)(A) of Nasdaq's Marketplace Rules, which requires a listed issuer to have at least three members on its audit committee. The Company received a letter in response from the Nasdaq Stock Market on March 22, 2005 to the same effect. The Company has also notified the Nasdaq Stock Market that it will rely on the cure period provision of Nasdaq Marketplace Rule 4350(d)(4)(B), which permits the Audit Committee to be composed of only two members on a temporary basis. The Board of Directors will appoint a third independent director to serve as a member of the Audit Committee to fill the vacancy by the date of the 2005 Annual Meeting of Stockholders in accordance with the terms of the cure period rule. In addition, the Board has determined that at least one member of the Audit Committee, Mr. Robert W. Shower, is an "audit committee financial expert." In addition to the positions described in Mr. Shower's biography earlier in this Proxy Statement, he has experience as a public accountant and chief financial officer and has served on the audit committees of other public companies.

The Audit Committee has direct responsibility for the appointment, retention, compensation and oversight of the independent registered public accounting firm for the purpose of preparing the Company's annual audit report or performing other audit, review or attest services for the Company. The Audit Committee has sole authority to approve all engagement fees and terms of the independent registered public accounting firm and to establish policies and procedures for pre-approval of audit and non-audit services. The Audit Committee conducts a review of the annual audit with management and the independent registered public accounting firm prior to filing or distribution, reviews filings with the SEC and other published documents containing the Company's financial statements, reviews with the Company's legal counsel any legal or regulatory matters that may have a material impact on the Company's financial statements, related corporate compliance policies, and programs and reports received from regulators. The Committee also reviews on an annual basis, or more frequently as such Committee may from time to time deem appropriate, the policies and practices of the Company dealing with various matters relating to the financial condition and auditing procedures of the Company, including financial information to be provided to stockholders and others, the Company's systems of internal controls established by management and oversight of the annual audit and review of the annual and quarterly financial statements, as well as any duties that may be assigned by the Board of Directors from time to time. The Audit Committee operates under a written charter that was last amended by the Board of Directors in December 2003 (as amended, the "Audit Committee Charter").

Corporate Governance/Nominating Committee. The members of the Corporate Governance/Nominating Committee of the Board are Messrs. Raphael, Sfondrini and Work, each of whom has been determined to be independent within the meaning of Marketplace Rule 4200(a)(15) of the Nasdaq Stock Market. Until his recent death, Mr. Musolino was a member and chairman of the Corporate Governance/Nominating Committee. The Board of Directors will designate a new chairman of the Corporate Governance/Nominating Committee by the date of the 2005 Annual Meeting of Stockholders. In December 2003, the Board established a charter for the Corporate Governance/Nominating Committee (the "Corporate Governance/Nominating Committee Charter") setting forth the purpose, goals and responsibilities of the Corporate Governance/Nominating Committee. The functions performed by the Committee are to make non-binding recommendations with respect to the nomination of directors to serve on the Board of Directors of the Company for the Board's final determination and approval, review the Board's corporate governance guidelines annually, undertake CEO succession planning and any other duties that may be assigned by the Board from time to time.

In December 2003, the Corporate Governance/Nominating Committee recommended and the full Board approved a set of corporate governance guidelines for guiding the Board in fulfilling its duties to the Company, including guidelines for the size of the Board, monitoring and safeguarding the independence of the Board, term limits, mandatory retirement, other directorships, change in occupation or business of a director, recusal when conflicts of interest arise, selection and qualification of director candidates, director continuing education, Board meetings, executive sessions with only non-employee directors, attendance, committees, Board and committee evaluations, CEO evaluation (by the Compensation Committee), management succession, procedures for communication by interested parties with non-employee directors, procedures for handling concerns regarding accounting, controls over financial reporting or other audit matters, non-employee director remuneration, certain shareholder voting matters and procedures for candidates recommended by shareholders and other matters (the "Corporate Governance Guidelines").

The Corporate Governance/Nominating Committee Charter provides, among other things, that any candidate for the Board nominated by the Board must meet the minimum qualifications specified in the charter and in the Company's Corporate Governance Guidelines, including that the director candidate possess personal and professional integrity, has good business judgment, relevant experience and skills and will be an effective director in conjunction with the full Board in collectively serving the long-term interests of the Company's stockholders. In addition, for a director to serve on the Audit, Compensation or Corporate Governance/Nominating Committee, he or she must meet the independence standards applicable to such committees in accordance with Nasdaq, the Internal Revenue Code and SEC rules. The Company's Bylaws provide that no person shall be eligible for nomination for election as a director if that person is or will become 70 years of age or older on or prior to the date of the annual meeting at which they would be considered for election. A director who becomes 70 years of age during his or her term may complete the term. The Company's Bylaws also provide that directors who are also employees of the Company are deemed to resign from the Board on their 65th birthday and may not thereafter be nominated for election. The Board may waive either or both of these Bylaw provisions by majority vote if the Board in its judgment determines that such waiver would be in the best interests of the Company. Inasmuch as Mr. Elias will turn 65 years of age in 2005, the Board considered and approved a resolution at its February 2005 meeting waiving the employee-director age restriction as it relates to Mr. Elias for the remainder of his term and providing that Mr. Elias shall remain eligible to be nominated for election to the Board in the future until he reaches the age of 70.

Director Nominations. All director nominations must be recommended by the Corporate Governance/ Nominating Committee and approved by a majority of the independent directors of the Board. The Corporate Governance/Nominating Committee's policy is that it will consider candidates recommended by stockholders on the same basis as other candidates, provided the recommended candidate meets all of the minimum requirements and qualifications for being a director as specified in the Company's Corporate Governance Guidelines, the Corporate Governance/Nominating Committee Charter and the Company's Bylaws. Any such recommendations should include the candidate's name and qualifications for Board membership and should be sent in writing to the

Corporate Secretary of the Company at Edge Petroleum Corporation, 1301 Travis, Suite 2000, Houston, Texas 77002. The Corporate Governance/Nominating Committee will consider candidates for Board membership suggested by its members and other Board members, as well as management and stockholders. Once the Committee identifies a prospective nominee, it will make an initial determination as to whether to conduct a full evaluation of the candidate. This initial determination will be based on whatever information is provided to the Committee with the recommendation of the prospective candidate, as well as the Committee's own knowledge of the prospective candidate, which may be supplemented by inquiries to the person making the recommendation or others. The initial determination will be based primarily on the need for Board members to fill vacancies or expand the size of the Board and the likelihood that the prospective nominee can satisfy the minimum qualifications described above. In addition, as the Company evolves, the experience and diversity required on its Board may change. Therefore, the expertise that a prospective nominee possesses will be thoroughly examined to determine whether there is an appropriate fit. If the initial determination indicates that the Committee should pursue the prospect, the Committee will evaluate the prospective nominee against the minimum qualifications in full and consider such other relevant factors as it deems appropriate. In connection with this evaluation, one or more members of the Committee and others as appropriate, may interview the prospective nominee. After completing this evaluation, the Committee will determine whether to recommend the individual for nomination by the Board. The Board, acting on the recommendations of the Corporate Governance/Nominating Committee, will nominate a slate of director candidates for election at each annual meeting of stockholders and will appoint directors to fill vacancies between annual meetings, including vacancies created as a result of any increase in size of the Board. The Company does not pay a fee to any third party or parties to identify, evaluate or assist in identifying or evaluating any potential nominees.

In addition, the Company's Bylaws permit stockholders to nominate persons for election to the Board at an annual stockholders meeting, without regard to whether the stockholder has submitted a recommendation to the Corporate Governance/Nominating Committee as to such nominee. To nominate a director using this process, the stockholder must follow the procedures described under "Additional Information."

Board Meetings. The Company expects each director to make every effort to attend each Board meeting, each meeting of any committee on which he or she sits and the annual stockholder's meeting. Attendance in person at board and committee meetings is preferred, but attendance by teleconference is permitted, if necessary. All of the Company's directors attended last year's annual meeting of stockholders.

During 2004, the Board of Directors held seven meetings and acted by written consent five times. During 2004, the Compensation Committee met three times, the Audit Committee met six times and the Corporate Governance/Nominating Committee met two times. During 2004, all members of the Board of Directors attended at least 75% of the total of all Board meetings and applicable committee meetings held during the time they served as directors. In addition, the Company's non-employee Directors meet at regularly scheduled executive sessions without management present. In 2004, the Board held four regularly scheduled executive sessions in which only the independent, non-employee Directors were present.

The Compensation Committee, Audit Committee and Corporate Governance/Nominating Committee Charters, as well as the Corporate Governance Guidelines are all available on the Company's website, *http://www.edgepet.com.* We make our website content available for information purposes only. It should not be relied upon for investment purposes, nor is it incorporated by reference in this Proxy Statement.

Director Remuneration — Prior to June 1, 2004, the annual compensation of each director who was not an employee of the Company or a subsidiary (a "Non-employee Director") consisted of (1) an annual retainer of $10,000, up to half of which could be paid in unrestricted shares of Common Stock and (2) a grant of non-qualified stock options ("NSOs") to purchase 3,000 shares of Common Stock. The shares of Common Stock and options for Common Stock were issued pursuant to the Edge Petroleum Corporation Incentive Plan.

Effective beginning June 1, 2004, the annual compensation for Non-employee Directors was revised to eliminate the stock option grant component and increase the annual retainer, all or a portion of which may be paid in shares of Common Stock. If the Board elects to pay all or some of the retainer in shares of Common Stock, all or a portion of those shares may be subject to restriction, in the discretion of the Board. The Edge Petroleum Corporation Incentive Plan was amended and restated effective June 1, 2004 accordingly (as amended and restated, the "Incentive Plan"). Under the Incentive Plan, the Board has the discretion to reinstate the annual option grant. In accordance with the new annual compensation arrangement, in 2004 Non-employee Directors were paid an annual retainer equal to the sum of (1) $10,000 (paid in cash) and (2) the value of 2,400 shares of Common Stock (paid in kind). The shares vest ratably over three years beginning on the first anniversary of the grant date. The fair market value of the shares on the June 1, 2004 award date was $32,640 per director. No option awards were made to Non-employee Directors in 2004.

In addition, each Non-employee Director is to receive a $1,000 cash payment for in-person attendance at a meeting of the Board of Directors ($400 if such attendance is telephonic) and $750 ($1,200 in the case of a chairman of a Committee even if such attendance is telephonic) for each meeting of a Committee of the Board of Directors attended ($400 if telephonic). All directors are reimbursed for out-of-pocket expenses incurred in attending meetings of the Board or Board committees and for other expenses incurred in their capacity as directors.

At its February 2005 meeting, the Corporate Governance/Nominating Committee reviewed the director's compensation and determined that such compensation should be increased in light of the increased duties, responsibilities and complexities of Board service. The committee deferred taking any action to increase director compensation, however, until after reviewing certain competitive information and surveys of director compensation of the Company's peers and competitors. Increases, if any, in director compensation will be finally reviewed and approved by the Corporate Governance/Nominating Committee at a meeting later in 2005, submitted to the full Board for approval and reported in the proxy statement for the 2006 annual meeting.

Audit Committee Report — As noted above, the Audit Committee is currently composed of two directors, Messrs. Andrews and Shower, and, until his recent death, Mr. Musolino, each of whom is independent as defined by the Nasdaq Stock Market's listing standards. Management is responsible for the Company's internal controls and financial reporting process. The independent registered public accounting firm was responsible for performing an independent audit of the Company's consolidated financial statements in accordance with auditing standards generally accepted in the United States of America and to issue a report thereon. The Audit Committee's responsibility is to monitor and oversee these processes.

In connection with these responsibilities, the Audit Committee met with management and the independent registered public accounting firm to review and discuss the December 31, 2004 financial statements. Management represented to the Audit Committee that the Company's consolidated financial statements were prepared in accordance with generally accepted accounting principles. The Audit Committee also discussed with the independent registered public accounting firm the matters required to be discussed by Statement on Auditing Standards No. 61 (Communication with Audit Committees, as amended). The Audit Committee also received written disclosures from the independent registered public accounting firm required by Independence Standards Board Standard No. 1 (Independence Discussions with Audit Committees), and the Audit Committee discussed with the independent registered public accounting firm that firm's independence.

Based upon the Audit Committee's discussions with management and the independent registered public accounting firm and the Audit Committee's review of the representations of management and the independent registered public accounting firm, the Audit Committee recommended that the Board of Directors include the audited consolidated financial statements in the Company's Annual Report on Form 10-K for the year ended December 31, 2004, to be filed with the Securities and Exchange Commission.

The Audit Committee:

Robert W. Shower, Chair
Vincent S. Andrews
Joseph R. Musolino*

* The Audit Committee, including Mr. Musolino, approved this report prior to his death.

Pursuant to the Securities and Exchange Commission Rules, the foregoing Audit Committee Report is not deemed "soliciting material", is not "filed" with the Commission and is not incorporated by reference with the Company's Annual Report on Form 10-K, whether made before or after the date hereof and irrespective of any general incorporation language in such report.

Security Ownership of Certain Beneficial Owners and Management — The following table sets forth information as of February 2, 2005 (except as indicated below) with respect to beneficial ownership of the Common Stock by: (i) all persons who are the beneficial owner of 5% or more of the outstanding Common Stock; (ii) each director or nominee for director; (iii) each executive officer of the Company; and (iv) all executive officers and directors of the Company as a group. As of February 2, 2005, 17,063,410 shares of Common Stock were issued and outstanding.

Name (1)	Number of Shares of Common Stock Beneficially Owned	Percent of Common Stock Beneficially Owned
John W. Elias (2)	655,370	3.75%
Michael G. Long (3)	92,844	*
John O. Tugwell (4)	66,362	*
Thurmon Andress (5)	12,000	*
Vincent S. Andrews (6)	40,705	*
Joseph R. Musolino (7)	10,000	*
Stanley S. Raphael (8)	237,173	1.39%
John Sfondrini (9)	26,311	*
Robert W. Shower (10)	29,197	*
David F. Work (11)	8,575	*
The Private Investment Fund and Marlin Capital Corp. (12)	925,000	5.42%
Mark G. Egan (12)	950,700 (13)	5.57%
All directors and executive officers as a group (10 persons) (14)	1,178,537	6.68%

* Less than one percent.

(1) Except as otherwise noted, each stockholder has sole voting and investment power with respect to the shares beneficially owned, subject to community property laws, where applicable.

(2) Shares shown include (i) 424,000 shares of Common Stock that could be acquired pursuant to stock options exercisable within 60 days of February 2, 2005, (ii) 215,000 shares purchased by Mr. Elias pursuant to the Company's 1999 private placement on the same terms as were applicable to unrelated parties; such shares are held in an IRA account for his benefit, and (iii) 2,370 shares that Mr. Elias will receive within 60 days of February 2, 2005 pursuant to a restricted stock award made on April 2, 2004.

(3) Shares shown include (i) 42,000 shares of Common Stock that could be acquired pursuant to stock options exercisable within 60 days of February 2, 2005, and (ii) 3,592 shares that Mr. Long will receive within 60 days of February 2, 2005, pursuant to restricted stock awards made in 2003 and 2004.

(4) Shares shown include (i) 37,000 shares of Common Stock that could be acquired pursuant to stock options exercisable within 60 days of February 2, 2005, and (ii) 3,592 shares that Mr. Tugwell will receive within 60 days of February 2, 2005, pursuant to restricted stock awards made in 2003 and 2004.

(5) Shares also include 5,000 shares of Common Stock that could be acquired pursuant to stock options exercisable within 60 days of February 2, 2005.

(6) Shares shown include (i) 15,000 shares of Common Stock beneficially owned by Mr. Andrews' wife, (ii) 3,568 shares held by Mr. Andrews' children, and (iii) 18,300 shares that could be acquired pursuant to stock options exercisable within 60 days of February 2, 2005. Mr. Andrews may be deemed the beneficial owner of the shares of Common Stock beneficially owned by his wife and children. Mr. Andrews disclaims such beneficial ownership.

(7) Shares also include 3,000 shares of Common Stock that could be acquired pursuant to stock options exercisable within 60 days of February 2, 2005.

(8) Shares shown include (i) 103,455 shares of Common Stock held by the Trade Consultants, Inc. Pension Plan, of which Mr. Raphael is the trustee, (ii) 50,986 shares held by the Stanley Raphael Trust, a trust controlled by Mr. Raphael, (iii) 47,208 shares held by a trust for the benefit of Mr. Raphael's wife, (iv) 15,000 shares held by Trade Consultants Inc. of which Mr. Raphael is sole owner and director, and (v) 18,300 shares that could be acquired pursuant to stock options exercisable within 60 days of February 2, 2005. Mr. Raphael may be deemed the beneficial owner of shares of Common Stock held by Trade Consultants, Inc. Pension Plan, Trade Consultants Inc. and the trust for the benefit of his wife. Mr. Raphael disclaims such beneficial ownership.

(9) Shares shown include (i) 450 shares of Common Stock held by Edge Holding Company, a limited partnership of which Mr. Sfondrini and a corporation wholly owned by him are the general partners, (ii) 809 shares held by Napamco, Ltd., a corporation wholly owned by Mr. Sfondrini of which he is the President, (iii) 4,998 shares held by Mr. Sfondrini's children, and (iv) 9,000 shares that could be acquired pursuant to stock options exercisable within 60 days of February 2, 2005. Mr. Sfondrini may be deemed the beneficial owner of the shares held by Edge Holding Company and his children. Mr. Sfondrini disclaims such beneficial ownership.

(10) Shares shown include (i) 16,500 shares of Common Stock that could be acquired pursuant to stock options exercisable within 60 days of February 2, 2004, (ii) 7,697 shares held jointly by Mr. Shower and his spouse and (iii) 5,000 shares held in an IRA rollover account for the benefit of Mr. Shower.

(11) Shares also include 5,000 shares of Common Stock that could be acquired pursuant to stock options exercisable within 60 days of February 2, 2005.

(12) The business address of each of these beneficial holders is 875 N. Michigan Ave., Suite 3412, Chicago, Illinois 60611. Mark G. Egan is the sole shareholder and president of Marlin Capital Corp. and is a limited partner of The Private Investment Fund. Marlin Capital Corp. is the general partner of The Private Investment Fund. Marlin Capital Corp. has the authority to direct the investments of The Private Investment Fund and consequently to authorize the disposition and vote of the shares of Common Stock held by The Private Investment Fund. Mr. Egan may be deemed to have indirect beneficial ownership of the shares of Common Stock owned by The Private Investment Fund. The information regarding The Private Investment Fund, Marlin Capital Corp. and Mr. Egan (included in Notes 12 and 13), is based on a filing made with the SEC reflecting beneficial ownership of the Common Stock as of December 21, 2004.

(13) Shares shown consist of 925,000 shares of Common Stock owned by The Private Investment Fund and 25,700 shares of Common Stock owned by Mr. Egan.

(14) Shares shown include (i) 578,100 shares of Common Stock that may be acquired pursuant to stock options exercisable within 60 days of February 2, 2005, and (ii) 9,554 shares of restricted Common Stock that executive officers will receive within 60 days of February 2, 2005.

Compliance with Section 16(a) of the Exchange Act — Section 16(a) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), requires the Company's directors, executive officers and persons who beneficially own 10% or more of the Company's Common Stock to file with the SEC initial reports of ownership and reports of changes in ownership of Common Stock. Based solely on a review of the copies of such reports furnished to the Company and written representations that no other reports were required, the Company believes that during 2004 all its directors and executive officers and 10% or greater holders complied on a timely basis with all applicable filing requirements under Section 16(a) of the Exchange Act.

Executive Compensation — Set forth below is information regarding the compensation of the Company's Chief Executive Officer (the "CEO") and the other executive officers of the Company (together with the CEO, the "named officers").

Summary Compensation Table. The summary compensation table set forth below contains information regarding the combined salary, bonus and other compensation of each of the named officers for services rendered to the Company in 2004, 2003 and 2002.

SUMMARY COMPENSATION TABLE

		Annual Compensation (1)		Long Term Compensation		
Name and Principal Position	**Year**	**Salary**	**Bonus**	**Restricted Stock Awards (2)**	**Securities Underlying Options (Shares)**	**All Other Compensation (3)**
John W. Elias	2004	$350,000	(4)	$93,852	50,000	$4,040
Chairman of the Board, President	2003	$350,000	$200,000	—	50,000	$2,630
and Chief Executive Officer	2002	$350,000	$149,000	—	74,000	$2,630
Michael G. Long	2004	$178,500	(4)	$47,203	—	$6,500
Senior Vice President and	2003	$166,700	$ 59,000	$29,808	—	$6,000
Chief Financial Officer	2002	$159,500	$ 56,800	—	12,000	$5,500
John O. Tugwell	2004	$183,000	(4)	$47,203	—	$5,935
Senior Vice President	2003	$172,000	$ 59,000	$29,808	—	$6,000
and Chief Operating Officer	2002	$164,500	$ 57,900	—	12,000	$6,981

(1) Other annual compensation for the named individuals during each of 2004, 2003 and 2002 did not exceed the lesser of $50,000 or 10% of the annual compensation earned by such individual.

(2) Reflects restricted stock awards made pursuant to the Incentive Plan. The dollar value included in the table reflects the valuation at the time of the award. An award of 7,110 shares of restricted stock was made to Mr. Elias on April 1, 2004. The shares were not issued at the time of the award and will be issued ratably over three years beginning April 1, 2005. An award of 3,576 shares of restricted stock was made to each of Messrs. Long and Tugwell on April 1, 2004. The shares were not issued at the time of the award and will be issued ratably over three years beginning April 1, 2005 in accordance with the vesting schedule for the award. An award of 7,200 shares of restricted stock was made to each of Messrs. Long and Tugwell on April 1, 2003. The shares were not issued at the time of the award and will be issued ratably over three years beginning April 1, 2004 in accordance with the vesting schedule for the award. Awards of restricted stock, all of which provide that actual shares are issued only upon vesting, have also been made in prior periods. If actual shares had been issued at grant for the restricted stock awards made in 2004 and all prior periods, the number and value of restricted shares held by the named officers at December 31, 2004 would be as follows: Mr. Elias: 7,110 shares ($103,664); Mr. Long: 8,376 shares ($122,122); and Mr. Tugwell: 8,376 shares ($122,122).

(3) In the case of Mr. Elias, amounts shown represent payments by the Company for life insurance on his account. In the case of Messrs. Long and Tugwell, amounts shown represent the Company's contributions under its 401(k) Plan. No amounts are included for Mr. Tugwell for payments received by him in respect of overriding royalty interests granted prior to his becoming an executive officer.

(4) Bonus awards for 2004 performance are not determined as of the date of this proxy statement and will be reported in the Proxy Statement for the 2006 Annual Meeting. Bonuses consist of a targeted percentage of the executive officer's annual salary, subject to a maximum targeted percentage, and are determined by formula that is based 80% on achievement of the Company's performance objectives for the

year as established by the Compensation Committee and 20% on achievement of the individual's objectives. The Company's performance objectives are measured by certain operational and financial objectives, and the individual performance objectives are mutually agreed to by the Company and the executive officer and assessed by the Chief Executive Officer who makes recommendations to the Compensation Committee. See discussion under "Compensation Committee Report on Executive Compensation", below.

Option/SAR Grants. Shown below is further information on grants of stock options during 2004 to the named officers.

Name	Number of Securities Underlying Options Granted	% of Total Options Granted to Employees in Fiscal Year	Exercise Price ($/Share)	Expiration Date	Grant Date Present Value (1)
John W. Elias (2)	50,000	100%	$13.99	4/1/14	$333,123
Michael G. Long	-0-	—	—	—	—
John O. Tugwell	-0-	—	—	—	—

(1) Based on the Black-Scholes option-pricing model adapted for use in valuing executive stock options. The actual value, if any, that may be realized will depend on the excess of the underlying stock price over the exercise price on the date the option is exercised, so that there is no assurance the value realized will be at or near the value estimated by the Black-Scholes model. The estimated values under the model are based on the following assumptions: expected volatility based on historical volatility of daily Common Stock price of 72%, a risk-free rate of return based on a discount rate equal to a U.S. Treasury rate at the time of grant of 3.76%, no dividend yields, an expected option exercise period of eight years (with the exercise occurring at the end of such period) and no adjustment for the risk of forfeiture over the applicable vesting period.

(2) Mr. Elias was granted options for the purchase of 50,000 shares of Common Stock effective April 1, 2004 pursuant to the terms of his employment agreement. These options vest and become exercisable on April 1, 2006. Of the options, options for 37,000 shares were issued to Mr. Elias outside of the Incentive Plan and options for 13,000 shares were issued from the Incentive Plan. See discussion under "Equity Compensation Plan Information," below.

Option/SAR Exercises and 2004 Year-End Option/SAR Values. Shown below is information with respect to option exercises and the value of the outstanding options held by the named officers for the year ended December 31, 2004.

Name	Shares Acquired On Exercise	Value Realized	Number of Securities Underlying Unexercised Options/SARs at FY-End(#)		Value of Unexercised In-the-Money Options/SARs at FY-End (1)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
John W. Elias	—	—	374,000	100,000	$3,613,760	$564,500
Michael G. Long	15,000	$117,821	42,000	—	$ 333,405	—0-
John O. Tugwell	10,000	$ 78,074	37,000	—	$ 295,818	—0-

(1) The excess, if any, of the market value of Common Stock at fiscal year end ($14.58 per share) over the option exercise price, expressed in dollars.

401(k) Employee Savings Plan — The Company has a tax-qualified 401(k) Employee Savings Plan (the "401(k) Plan") for its employees generally, in which the executive officers also participate. Under the 401(k) Plan, eligible employees are permitted to defer receipt of their compensation up to the maximum amount allowed by law, with the employee's contribution not to exceed $14,000 for the current year (subject to certain limitations imposed under the Internal Revenue Code of 1986, as amended (the "Code")). The 401(k) Plan provides that a discretionary match of employee deferrals may be made by the Company in cash or stock. Pursuant to the 401(k) Plan, the Company has elected to match 50% of the first 8% of employee deferral, subject to limitations imposed by the Internal Revenue Service. The amounts held under the 401(k) Plan (except for matching contributions by the Company in Common Stock) are invested among various investment funds maintained under the 401(k) Plan in accordance with the directions of each participant. Except for customary "blackout" periods imposed from time to time by the Company on all employees including executive officers, the 401(k) Plan does not restrict employees from selling vested shares of the Company's Common Stock held in the plan. Salary deferral contributions by employees under the 401(k) Plan are 100% vested. Company contributions vest 50% at the completion of the first year of employment with the remaining 50% vesting at the completion of the second year of employment. All company contributions after the completion of the second year of employment are fully vested. Participants or their beneficiaries are entitled to payment of vested benefits upon termination of employment.

Employment Agreements and Change of Control Agreements — Mr. Elias entered into an employment agreement with the Company effective November 1998. The initial term of his employment agreement ended December 31, 2001. The agreement automatically renewed for a one-year term and will continue to do so at the end of each calendar year unless either party gives advance notice of non-renewal. Mr. Elias' employment agreement calls for a minimum base salary of $350,000 per year during the first three years of the employment agreement and may be increased thereafter at the discretion of the Compensation Committee. His employment agreement did not provide for an annual bonus for 1999. Thereafter he is afforded a bonus opportunity of up to 100% of base salary with a target incentive bonus of 50% of base salary keyed to specific performance objectives established by the Compensation Committee. In addition, the agreement provided for a January 1999 initial grant of NSOs for the purchase of 200,000 shares of Common Stock exercisable at fair market value of the Common Stock on the date of grant, having a ten-year term and becoming exercisable 1/3 upon issue, and 1/3 upon each of January 1, 2000 and January 1, 2001. The agreement also provides for subsequent grants of NSOs, at the discretion of the Board of Directors, on January 1 of the years 2000 through 2004 for 50,000 shares each exercisable at the fair market value of the Common Stock on the date of each subsequent grant. These subsequent options have a ten-year term and vest 100% on the second anniversary of the grant date. Such agreement also provides that the Company will provide a $1,000,000 term life insurance policy for Mr. Elias, together with a tax gross-up payment in the amount necessary to offset any applicable taxes imposed on him by reason of such insurance policy and gross-up. Upon termination of employment by the Company (except under certain limited circumstances defined as "for cause" in the agreement or upon certain material breaches of the agreement by Mr. Elias) or by Mr. Elias for certain reasons, such as the Company's material breach of the agreement or the assignment to Mr. Elias of duties inconsistent with his position as set forth in the agreement ("for good reason"), Mr. Elias will generally be entitled to certain benefits (the "Termination Benefits") including: (1) continued payment of his base salary then in effect for the unexpired portion of the term of the agreement; (2) immediate vesting of all outstanding stock options granted by the Company to him which will remain exercisable for a period of 12 months after such termination (but in no event beyond the expiration of the original term of such stock option grants); (3) a lump sum cash payment equal to his prorated incentive target bonus in the year of termination; (4) life insurance coverage and annual tax gross-up of premium payments shall continue to be provided for the unexpired portion of the term of the agreement; (5) cash payments equal to the amount credited to his account under any employee profit sharing plan or stock ownership plans that are forfeitable in accordance with the terms of such plans; and (6) participation for a period of 18 months after the date of termination in the Company's group health plan. The employment agreement of Mr. Elias provides for a covenant limiting competition with the Company during employment with the Company and, if the employment ends by reason of Mr. Elias' disability or his terminating his employment for good reason, for as long as the Company is providing him with Termination Benefits.

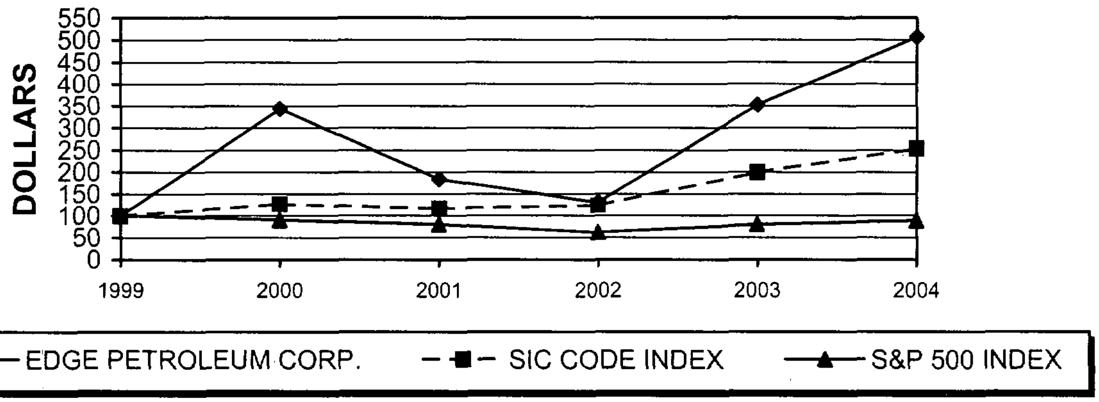
Messrs. Long and Tugwell are both employees at will of the Company.

All current employees of the Company, including Messrs. Elias, Long and Tugwell, are parties to a severance agreement that provides for certain benefits in the event of a "change of control" as defined in the agreement. Pursuant to such agreements if the named officers' employment by the Company is subject to an involuntary termination (which includes a voluntary resignation within sixty (60) days after, among other things, a significant reduction in duties of the employee or a reduction in annual salary, bonus or benefits) occurring within two (2) years after a change in control of the Company, the officer is entitled to receive a lump sum severance amount, which is 2.99 times annual salary and targeted annual bonus in Mr. Elias' case and 2.0 times annual salary and targeted annual bonus in the case of each of Messrs. Long and Tugwell. In addition, the employee would be entitled to the remaining portion of any prior years' incentive bonus award, continued coverage in Company welfare and benefit plans for up to thirty-six (36) months, certain outplacement services up to a maximum cost to the Company of $6,000, and a tax gross-up payment designed to keep the employee whole with respect to any taxes imposed by Section 4999 of the Code. Under the severance plan, a "change of control" occurs if: (i) the Company (A) shall not be the surviving entity in any merger, consolidation or other reorganization (or survives only as a subsidiary of an entity other than a previously wholly-owned subsidiary of the Company) or (B) is to be dissolved and liquidated, and as a result of or in connection with such transaction, the persons who were directors of the Company before such transaction shall cease to constitute a majority of the Board; (ii) any person or entity, including a "group" as contemplated by Section 13(d)(3) of the Exchange Act acquires or gains ownership or control (including, without limitation, power to vote) of 20% or more of the outstanding shares of the Company's voting stock (based upon voting power), and as a result of or in connection with such transaction, the persons who were directors of the Company before such transaction shall cease to constitute a majority of the Board; or (iii) the Company sells all or substantially all of the assets of the Company to any other person or entity (other than a wholly-owned subsidiary of the Company) in a transaction that requires stockholder approval pursuant to the Texas Business Corporation Act. It is estimated that in the event all of the Company's employees were terminated at March 14, 2005 pursuant to a change of control, the total severance payments owed for all employees pursuant to these severance agreements would be $8,258,689 (not including the costs of outplacement services and taxes), including $1,569,750 for Mr. Elias, $506,940 for Mr. Long and $519,720 for Mr. Tugwell.

Compensation Committee Interlocks and Insider Participation — The members of the Compensation Committee of the Board of Directors are Messrs. Andress (chairman), Shower and Work. Mr. Sfondrini served on the Compensation Committee until March 2004. During 2004, Mr. Sfondrini was subject to certain transactions and relationships with the Company relating to certain oil and natural gas business matters. These transactions and relationships are described under "Certain Transactions," later in this Proxy Statement. None of the Company's executive officers has served as a member of a compensation committee or board of directors of any other entity that has an executive officer serving as a member of the Company's Board of Directors.

Performance Graph — The following performance graph compares the cumulative total stockholder return on the Common Stock to the cumulative total return of the Standard & Poor's 500 Stock Index and an index composed of all publicly traded oil and gas companies identifying themselves by primary Standard Industrial Classification (SIC) Code 1311 (Crude Petroleum and Natural Gas) for the period beginning December 31, 1999 and ending December 31, 2004.

COMPARE 5-YEAR CUMULATIVE TOTAL RETURN AMONG EDGE PETROLEUM CORP., S&P 500 INDEX AND SIC CODE INDEX



ASSUMES $100 INVESTED ON DEC. 31, 1999
ASSUMES DIVIDEND REINVESTED

	Edge	SIC Code Index	S&P 500 Index
December 31, 1999...........	$100.00	$100.00	$100.00
December 29, 2000...........	$343.48	$127.04	$ 90.89
December 31, 2001...........	$184.35	$116.56	$ 80.09
December 31, 2002...........	$130.43	$124.27	$ 62.39
December 31, 2003...........	$352.00	$199.58	$ 80.29
December 31, 2004...........	$507.13	$253.54	$ 89.02

Pursuant to Securities and Exchange Commission Rules, the foregoing Performance Graph and the Compensation Committee Report that follows are not "soliciting material", are not deemed filed with the Commission and are not incorporated by reference with the Company's Annual Report on Form 10-K, whether made before or after the date hereof and irrespective of any general incorporation language in such report.

Compensation Committee Report on Executive Compensation — The members of the Compensation Committee consist of Messrs. Andress, Shower and Work. The Company's executive compensation has as its objectives to (a) further the achievement of the Company's financial objectives, (b) focus executives on attainment of growth and the creation of stockholder value over time and (c) attract and retain talented and motivated executives. The executive compensation program is intended to provide an overall level of compensation that the Compensation Committee believes, based on its own judgment and experience, is competitive with levels of compensation provided by other companies in the industry. The programs link each executive's compensation directly to individual and Company performance. A significant portion of each executive's total compensation is variable and dependent upon the attainment of operating and financial goals, individual performance objectives and the appreciation in value of the Common Stock.

Executive compensation primarily consists of three components: (a) base salary, (b) annual incentive compensation in the form of a cash bonus payment and (c) long-term equity-based incentive compensation. Each component is addressed in the context of individual and Company performance and competitive conditions. In determining competitive compensation levels, the Company analyzes data that includes information regarding compensation levels and programs in the oil and natural gas exploration and production industry, which was provided by a company that surveys and compiles annual energy compensation information. The Company's compensation scheme focuses on both short-term goals, through the awarding of annual bonuses, and long-term goals, through the awarding of stock options and restricted stock.

Individual salary levels, bonus awards and changes in remuneration of the individual executives are determined by the Compensation Committee or the Board as a whole, subject in the case of Mr. Elias, to the terms of his employment agreement. The Chief Executive Officer makes recommendations to the Compensation Committee regarding the salaries of and awards to employees. Actual grants or awards of stock, including stock options, as well as changes in salaries are individually determined and administered by the Compensation Committee or the Board as a whole (acting on the recommendation of the Compensation Committee), in each case taking into account recommendations from the Chief Executive Officer.

Base Salary. Base salaries of the executive officers (including that set forth in Mr. Elias' employment agreement) are determined based on the Compensation Committee's review of a number of factors, including comparable industry data and individual factors such as an executive's specific responsibilities, experience, individual performance and growth potential as well as independently obtained salary surveys. The Compensation Committee's salary recommendations are subject to approval of the full Board. Base salaries are designed so that salary opportunities for a given position will generally be between 90% and 100% of the competitive base salary midpoint established for each position. The employment contract of Mr. Elias requires the Compensation Committee to annually review his base salary and make a recommendation to the Board of Directors regarding possible increases. Such recommendations are made after careful review of the Company's and Mr. Elias' performance. Under the terms of Mr. Elias' employment agreement, the Board of Directors may, in its sole discretion, increase but not decrease his salary. No salary increase was recommended by the Compensation Committee or granted by the Board for Mr. Elias during 2004. The last merit increase for Messrs. Long and Tugwell was April 2004 and such increase was based on their performance.

Bonus. Under the Company's bonus program, the annual bonus of the executive officers is determined by recommendation of the Compensation Committee, after reviewing recommendations of the Chairman and Chief Executive Officer, which is then submitted to the full Board for approval. The amount of bonus that may be earned is based on a targeted percentage of the executive officer's annual salary, subject to a maximum-targeted percentage. The bonuses of the executive officers for 2004 are based 80% on achievement of the Company's performance objectives as established by the Compensation Committee and 20% on achievement of the individual's performance objectives. The Company's overall performance objectives are measured by certain operational and financial objectives. The operational objectives for the Company for 2004 consisted of targeted annual increases in reserves (weighted 40%) and production (weighted 30%), competitive finding and development costs (weighted 15%) and operating expenses (weighted 15%), as compared with those projected in the Company's annual budget for the applicable period. The financial goals for the Company for 2004 were: (1) to ensure that funds were available to execute the Company's overall recommended case capital spending program as projected in its 2004 annual budget and plan (the "Recommended Case") while maintaining a prudent financial structure with a debt-to-total capital ratio of less than 30%, subject to adjustment due to acquisitions; (2) to fund the Recommended Case, excluding acquisitions, from internal cash flow rather than taking on more debt; and (3) building pre-tax cash flow from our exploration and production activities to a level sufficient to provide the necessary funds to conduct a program that will provide consistent physical (reserve and production) and fiscal (cash flow and net income) growth for the Company.

Individual performance is assessed by a performance management process based on mutually defined expectations for each employee, including executive officers. The process includes individual appraisal components that are both objective and subjective. The objective components include quantifiable objectives and the subjective performance components include roles and accountabilities, performance attributes and behaviors. Individual performance of the executive officers, except the Chief Executive Officer, is first assessed by the Chief Executive Officer, who makes recommendations to the Compensation Committee for its consideration. Bonus opportunities for Messrs. Long and Tugwell for 2004 ranged from 0% to 80% of base salary. Mr. Elias' employment agreement provides a bonus opportunity ranging from 0% to 100% of his base salary subject to the achievement of specific objective and subjective performance criteria established mutually between the Compensation Committee and Mr. Elias on an annual basis. For 2004, the Board determined that a bonus for Mr. Elias would be determined based 80% on the achievement of the same Company performance criteria applicable to the other executive officers and 20% on the achievement of certain individual performance objectives as determined by the Compensation Committee and approved by the full Board. Bonus awards to be paid, if any, for 2004 performance are not determined as of the date of this Proxy Statement and will be reported in the Proxy Statement for the 2006 Annual Meeting.

Under the bonus program, the 2004 bonuses will be paid in cash. All bonuses are subject to the final approval of the Board of Directors.

Long-Term Equity-Based Compensation. The Company has relied on grants of stock options and grants of restricted stock under its Incentive Plan and, in the case of Mr. Elias, outside of the Incentive Plan, to provide long-term incentive-based compensation. The objectives of the Incentive Plan are to (i) attract and retain the services of key employees, qualified independent directors and qualified consultants and other independent contractors and (ii) encourage the sense of proprietorship and stimulate the active interest of those persons in the development and financial success of the Company. At December 31, 2004, options under the Incentive Plan had been granted to 58 current and former employees and directors, at exercise prices ranging from $2.11 per share to $13.99 per share. In 2004 the Company determined not to grant to employees any options to purchase shares of stock of the Company (except as required under the terms of employment agreements). Pursuant to the terms of his employment agreement, Mr. Elias was granted options to purchase 50,000 shares of Common Stock in April 2004 at an exercise price equal to the fair market value of the Common Stock on the date of grant. These options vest in full on the second anniversary of the date of grant and 13,000 of these shares subject to the options are issuable under the Incentive Plan, with the remaining 37,000 shares issuable under the Elias Plan, as defined below under "Equity Compensation Plan Information".

Restricted stock awards are made to executive officers as part of their long-term equity-based compensation. Such awards are made by the Compensation Committee. Relevant factors in the determination of grants include data regarding stock grants at comparable companies and recommendations of the Chief Executive Officer. In determining the amount of shares to award executive officers, the Compensation Committee also considers, among other things, the relative grade levels of the officers. The restricted stock awards are designed to encourage executive officers to retain an ownership interest in the Company, to align their interests with those of stockholders and to reward increases in the Company's share price over time. A restricted stock award is a grant of a right to receive shares that vests over time. As the stock award vests, the shares are owned outright. The currently outstanding restricted stock held by executive officers vests and is issued in equal one-third increments on the first, second and third anniversary of the date of grant. In the last two years, the Compensation Committee has recommended the award of restricted stock instead of, or in addition to, options because in the view of the Compensation Committee, restricted stock is a better way to provide significant equity compensation that can generate more predictable long-term rewards than stock options.

Grants of stock options to executive officers may be made by the Compensation Committee. The employment agreement of Mr. Elias sets forth the number and terms of his initial and subsequent option grants through 2004. All other grants are made at the discretion of the Compensation Committee or the Board as a whole. Awards of options are determined on the basis of factors similar to those used to determine awards of restricted stock. The exercise price of all stock options has been equal to at least the fair market value of the Common Stock on the date of grant; accordingly, executives receiving stock options are rewarded only if the market price of the Common Stock appreciates. Stock options are thus designed to align the interests of the Company's executives with those of its stockholders by encouraging executives to enhance the value of the Company and hence, the price of the Common Stock and each stockholder's return.

Since the Company's initial public offering, certain non-executive employees of the Company received grants of overriding royalty interests in oil and gas prospects of the Company where such interests had been earned pursuant to employment agreements between such employees and the Company. Effective June 1, 1999 all employment agreements which provided for overriding royalty interests were terminated. Pursuant to a policy adopted as of that date, no employee of the Company is entitled to an overriding royalty interest on any prospect that is defined and leased after July 1, 2000. Overrides which were earned in prospects prior to July 1, 2000 or assigned of record remain valid. Executive officers of the Company have not been entitled to receive overriding royalty grants since the Company's initial public offering. Prior to becoming an executive officer, Mr. Tugwell received overriding royalty interests under the Company's prior practice and has, and will in the future, receive payments pursuant to such interests.

Section 162(m) of the Internal Revenue Code. Section 162(m) of the Internal Revenue Code of 1986, as amended, generally limits (to $1 million per covered executive) the deductibility for federal income tax purposes of annual compensation paid to company's executive officers in a taxable year. Compensation above $1 million may be deducted if it is "performance-based compensation" within the meaning of the Code. Options grants that are made outside of stockholder-approved plans, such as most of the options grants made to Mr. Elias, are generally subject to the deductibility limits of Section 162(m). The Compensation Committee seeks to qualify compensation for deductibility in certain instances, but retains the discretion to authorize the payment of nondeductible amounts.

Compensation of Chief Executive Officer. Mr. Elias' compensation, as described above, is generally determined in part by the terms of his employment agreement, which was approved by the Board as a whole and the Compensation Committee. In doing so, the Board and Compensation Committee considered a variety of factors, including a review of comparable industry data, the compensation package of Mr. Elias' predecessor at the Company and negotiations between Mr. Elias and the Compensation Committee. In addition to the compensation contemplated by his employment agreement, Mr. Elias was awarded 7,110 shares of restricted stock in 2004. The Compensation Committee recommended this award in recognition of his leadership in moving the Company forward in a positive manner and his expected future contributions.

The Compensation Committee:

Thurmon Andress, Chair
Robert W. Shower
David F. Work

Equity Compensation Plan Information — The following table provides certain information with respect to all of the Company's equity compensation plans in effect as of December 31, 2004.

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights (1)	(b) Weighted average exercise price of outstanding options, warrants and rights (2)	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (3)
Equity compensation plans approved by security holders	508,835	$6.39	454,485
Equity compensation plan not approved by security holders	461,000	$5.53	—
Total	969,835	$5.91	454,485

All amounts set forth opposite "Equity compensation plans approved by security holders" relate to the Incentive Plan. Amounts set forth opposite "Equity compensation plan not approved by security holders" relate to the Amended and Restated Edge Petroleum Corporation Elias Stock Incentive Plan (the "Elias Plan"), which is described below.

(1) The shares set forth in column (a) are comprised of shares of Common Stock that may be issued in the future pursuant to currently outstanding options for the purchase of Common Stock and shares of Common Stock that may be issued in the future pursuant to currently outstanding restricted stock awards. In the case of restricted stock awards, the Company does not actually issue shares of Common Stock until and to the extent the awards vest. The amounts set forth in column (a) include 147,785 shares with respect to the Incentive Plan that may be issued in the future pursuant to currently outstanding restricted stock awards.

(2) The calculations of weighted average exercise prices are exclusive of restricted stock awards. In the case of equity compensation plans approved by security holders, the amount is based solely on options to purchase 361,050 shares of Common Stock pursuant to the Incentive Plan. In the case of equity compensation plans not approved by security holders, the amount is based on options to purchase 461,000 shares of Common Stock pursuant to the Elias Plan.

(3) All of the shares set forth in column (c) with respect to the Incentive Plan may be issued pursuant to stock awards, including stock options, restricted stock grants and stock appreciation rights.

The Elias Plan was approved by the Board of Directors of the Company and 475,000 shares of Common Stock were reserved for issuance thereunder, of which no shares remain available for additional awards at December 31, 2004. Under the Elias Plan, awards may be made to Mr. Elias of options for the purchase of Common Stock and of restricted stock. As of December 31, 2004, options for the purchase of 461,000 shares of Common Stock and a restricted stock award relating to 14,000 shares of Common Stock had been made to Mr. Elias under the Elias Plan. The Elias Plan was adopted to induce and retain the employment of Mr. Elias and to stimulate his active interest in the development and financial success of the Company. Mr. Elias' employment agreement contemplates the issuance to him of options for the purchase of up to 450,000 shares of Common Stock, all of which options had been issued under the Elias Plan as of December 31, 2004. The Elias Plan provides for the issuance of an initial option award to Mr. Elias for the purchase of 200,000 shares of Common Stock effective January 8, 1999, which became exercisable in increments of one-third of the shares subject thereto annually beginning on the date of grant, has a term of ten years and an exercise price equal to the fair market value of the Common Stock on the date of grant. The Elias Plan provides that all subsequent option awards under the Elias Plan, which may be made in the sole discretion of the Board, be of options with a ten-year term, becoming exercisable in full upon the second anniversary of the date of grant and with an exercise price not less than the fair market value of the Common Stock on the date of grant. Pursuant to the Elias Plan, the Board approved grants of NSOs to purchase 50,000 shares of Common Stock effective on or about January 1 of each of the years 2000 through and including 2003. For 2004, options for the purchase of 37,000 shares were issued to Mr. Elias under the Elias Plan and options for the purchase of 13,000 shares were issued to him under the Incentive Plan. All options were granted at an exercise price equal to the fair market value of the Common Stock on the date of grant. The Elias Plan provides for an award of 14,000 shares of restricted stock to Mr. Elias effective March 1, 2001, which vests in increments of one-third of the shares subject thereto annually beginning on the first anniversary of grant. An option award to Mr. Elias for the purchase of 24,000 shares of Common Stock was made from the Elias Plan on April 1, 2002, which becomes exercisable in full upon the second anniversary of the date of grant at an exercise price equal to the fair market value of the Common Stock on the date of grant.

Certain Transactions

The transactions described below were carried out on terms at least as favorable to the Company as could have been obtained from unaffiliated third parties in arm's length negotiations, however, because the transactions were with parties that may be deemed to be affiliates, it is possible that the Company would have obtained different terms from a truly unaffiliated third-party.

Affiliates' Ownership in Prospects. Edge Group Partnership, a general partnership composed of limited partnerships of which Mr. Sfondrini and a company controlled by Mr. Sfondrini are general partners, Edge Holding Company, L.P., a limited partnership of which Mr. Sfondrini and a corporation wholly owned by him are the general partners, Andex Energy Corporation and Texedge Energy Corporation, corporations of which Mr. Andrews is an officer and members of his immediate family hold ownership interests, Mr. Raphael, Essex Royalty Joint Venture I ("Essex I") and Essex Royalty Joint Venture II ("Essex II"), both being joint venture partnerships of which Mr. Sfondrini and a company wholly owned by Mr. Sfondrini are managers, own certain working interests in the Company's Nita and Austin Prospects and certain other wells and prospects operated by the Company. These working interests aggregate 7.19% in the Austin Prospect, 6.27% in the Nita Prospect and are negligible in other wells and prospects. These working interests bear their share of lease operating costs and royalty burdens on the same basis as the Company. Amounts paid to these entities and individual by the Company represent their respective pro-rata ownership shares in the particular properties involved. In addition, Bamaedge, L.P., a limited partnership of which Andex Energy Corporation is the general partner, and Mr. Raphael also hold overriding royalty interests with respect to the Company's working interest in certain wells and prospects. Neither Mr. Raphael nor Bamaedge L.P. has an overriding interest in excess of .075% in any one well or prospect. Essex I and Essex II own royalty and overriding royalty interests in various wells operated by the Company. The combined royalty and overriding royalty interests of Essex I and Essex II do not exceed 6.2% in any one such well or prospect. The gross amounts distributed or accrued to these persons and entities by the Company in 2004 on account of their proportionate ownership interests (including net revenue, royalty and overriding royalty interests) and the amounts these same persons and entities paid to the Company for their respective share of lease operating expenses and other costs is set forth in the following table:

Owner	Total Amounts Paid by the Company to Owners in 2004 including Overriding Royalty*	Lease Operating Expenses paid to the Company by Owners in 2004
Andex Corporation/ Texedge Corporation	$ 3,896	$ 2,578
Bamaedge, L.P.	$ 3,594	-0-
Edge Group Partnership	$387,603	$40,284
Edge Holding Co., L.P.	$ 71,177	$ 7,065
Essex I Joint Venture	$ 32,603	-0-
Essex II Joint Venture	$150,509	$ 5,629
Stanley Raphael	$ 5,209	$ 412
Total	$654,591	$55,968

* In the case of Essex I and II Joint Ventures, amounts include royalty income in addition to working interest income

Code of Ethics

The Company has adopted a code of ethics that applies to all Company employees including executive officers, as well as each member of the Company's Board of Directors. The code of ethics is available at the Company's website at *http://www.edgepet.com.* The code includes policies on employment, conflicts of interest, and the protection of confidential information and requires adherence to all laws and regulations applicable to the conduct of our business.

PROPOSAL II

Proposed Charter Amendment to Increase the Number of Authorized Shares of Common Stock

The Board has approved a resolution proposing that the Company's Restated Certificate of Incorporation, as amended to date (the "Charter"), be further amended to increase the number of authorized shares of Common Stock of the Company to Sixty Million (60,000,000) shares (the "Amendment").

The proposed Amendment would replace the first sentence of Article Four of the Charter with the following sentence:

> "The aggregate number of shares of capital stock that the Corporation shall have authority to issue is Sixty-five Million (65,000,000), divided into Sixty Million (60,000,000) shares of common stock, par value $0.01 per share ("Common Stock"), and Five Million (5,000,000) shares of preferred stock, par value $0.01 per share ("Preferred Stock")."

Current Capital Structure

Under Delaware law, the Company may only issue shares of capital stock to the extent such shares have been authorized for issuance under the Charter. The Charter currently authorizes the Company to issue Twenty-five Million (25,000,000) shares of Common Stock and Five Million (5,000,000) shares of preferred stock, par value $0.01 per share ("Preferred Stock"). As of March 1, 2005, 17,063,910 shares of Common Stock were issued and outstanding and 4,792,831 shares of Common Stock were reserved for issuance. After taking into account such reserved shares, a balance of 3,143,259 authorized but unissued shares of Common Stock would be available for issuance under the Charter as it now exists. No shares of Preferred Stock as of such date were issued and outstanding or reserved for issuance.

Reasons for Amendment

The number of issued and outstanding shares of Common Stock has increased from 7,461,361 in March 1997 to 17,063,910 on March 1, 2005. As a result, the Company's available Common Stock has been reduced. In this light, the Board deems it advisable and in the best interest of stockholders to increase the number of shares of Common Stock authorized for issuance by the Company from 25 million to 60 million. The additional 35 million shares of Common Stock to be authorized would be available for possible future financing and acquisition transactions, stock dividends or stock splits, employee benefit plans and other corporate purposes. Having such shares available for issuance in the future would give the Company greater flexibility and would generally allow shares of Common Stock to be issued without the expense and delay of a special stockholders' meeting.

Immediately after its initial public offering in March 1997, the Company had 7,461,361 shares of Common Stock issued and outstanding, all of which were issued in the initial public offering and the combination transactions effected concurrently therewith. Since then, the Company has issued (i) 1,171,945 shares of Common Stock in connection with various benefit and incentive plans, (ii) 2,240,000 shares of Common Stock pursuant to a private placement of Common Stock and warrants (all of which have been exercised) in June 1999, (iii) 2,165,604 shares of Common Stock in connection with the December 2003 acquisition of Miller Exploration Company and (iv) 4,025,000 shares of Common Stock in connection with a December 2004 public offering of Common Stock, for a total of 17,063,910 shares issued and outstanding as of March 1, 2005.

If the Amendment is approved by the stockholders, the Board does not intend to solicit further stockholder approval prior to the issuance of any additional shares of Common Stock, except as may be required by applicable law or the rules of any stock exchange or quotation system on which the Common Stock may be listed or quoted. The Nasdaq Stock Market, on which the Common Stock is quoted, currently requires stockholder approval in certain instances, including in connection with acquisition transactions where the present or potential issuance of shares is or will be equal to or in excess of 20% of the number of shares of Common Stock outstanding before the issuance of the stock.

The proposed Amendment could, under certain circumstances, have an anti-takeover effect, although this is not the intention of this proposal. For example, in the event of a hostile attempt to take over control of the Company, it may be possible for the Company to endeavor to impede the attempt by issuing shares of Common Stock, which would dilute the voting power of the other outstanding shares and increase the potential cost to acquire control of the Company. The proposed Amendment therefore may have the effect of discouraging unsolicited takeover attempts and potentially limiting the opportunity for the Company's stockholders to dispose of their shares at a premium, which is often offered in takeover attempts, or that may be available under a merger proposal. The proposed Amendment may have the effect of permitting the Company's current management, including the current Board, to retain its position, and place it in a better position to resist changes that stockholders may wish to make if they are dissatisfied with the conduct of the Company's business. However, the Board is not aware of any attempt to take control of the Company, and the Board has not presented this proposal with the intent that it be utilized as a type of anti-takeover device. The Board has no current plans for the issuance of the additional shares of Common Stock for which authorization is being sought, except in connection with equity compensation plans.

To the extent that additional authorized shares are issued in the future, they may decrease the existing stockholders' percentage equity ownership and depending on the price at which they are issued, could be dilutive to the existing stockholders. The holders of Common Stock have no preemptive rights and the Board of Directors has no plans to grant such rights with respect to any such shares.

If the proposed Amendment is adopted, it will become effective upon filing of a Certificate of Amendment to the Charter with the Secretary of State of the State of Delaware.

Required Vote and Board of Directors Recommendation

Approval of the Amendment will require the affirmative vote of the holders of at least a majority of the outstanding shares of Common Stock outstanding on the record date. The persons named in the accompanying proxy will vote in accordance with the choice specified thereon, or, if no choice is properly indicated, in favor of the adoption of the Amendment. Abstentions and broker non-votes will be counted as present for the purposes of determining if a quorum is present, but will have the same effect as a vote against the Amendment. A failure to vote shares will also have the effect of a vote against the Amendment.

The Board of Directors recommends that stockholders vote FOR the adoption of the proposed Amendment.

PROPOSAL III

Approval of Appointment of Independent Registered Public Accounting Firm

The Board of Directors, upon recommendation of its Audit Committee, has approved and recommends the appointment of BDO Seidman, LLP as an independent registered public accounting firm to conduct an audit of the Company's financial statements for the year 2005. Although the selection and appointment of an independent registered public accounting firm is not required to be submitted to a vote of stockholders, the Board of Directors has decided to ask our stockholders to approve this appointment. In accordance with the Company's Bylaws, approval of the appointment of an independent registered public accounting firm will require the affirmative vote of a majority of the shares of Common Stock voted at the meeting. Accordingly, abstentions and broker non-votes applicable to shares present at the meeting will not be included in the tabulation of votes cast on this matter.

Representatives of BDO Seidman, LLP will attend the Annual Meeting and will be available to respond to questions that may be asked by stockholders. Such representatives will also have an opportunity to make a statement at the meeting if they desire to do so.

The Board of Directors recommends that stockholders vote FOR the appointment of BDO Seidman, LLP as the Company's independent registered public accounting firm.

Change in Independent Registered Public Accounting Firm

On June 25, 2004, the Company dismissed its independent accountant, KPMG LLP and engaged BDO Seidman, LLP as its new independent registered public accounting firm and auditor. The decision to engage BDO Seidman, LLP and dismiss KPMG LLP was approved by the Audit Committee.

As noted in the Company's Current Report on Form 8-K filed on June 30, 2004, none of the reports of KPMG LLP on the financial statements of the Company during their engagement contained an adverse opinion or was qualified or modified as to uncertainty, audit scope or accounting principles except as follows: KPMG LLP's audit reports on the consolidated financial statements of Edge Petroleum Corporation and subsidiaries as of and for the years ended December 31, 2003 and 2002, contained a separate paragraph stating that "As discussed in Note 2 to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations and effective January 1, 2001, the Company changed its method of accounting for derivative instruments." These changes were made and this explanatory language was included pursuant to the required adoption on January 1, 2003 of Statement of Financial Accounting Standard ("SFAS") No. 143, "Accounting for Asset Retirement Obligations," and the required adoption on January 1, 2001 of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.

Further, during the Company's two fiscal years ended December 31, 2003 and for the period from January 1, 2004 to June 25, 2004, there were no disagreements between the Company and KPMG LLP on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreement, if not resolved to the satisfaction of such accountants, would have caused them to make reference to the subject matter of the disagreements in connection with their report on the financial statements for such years. There were no reportable events (as defined in Regulation S-K, Item 304 (a)(1)(v)) during the Company's two fiscal years ended December 31, 2003 and for the period from January 1, 2004 to June 25, 2004. During the Company's two fiscal years ended December 31, 2003 and for the period from January 1, 2004 to June 25, 2004, the Company did not consult with BDO Seidman, LLP regarding any of the matters or events set forth in Item 304(a)(2)(i) or (ii) of Regulation S-K.

Independent Public Accountants' Fees

BDO Seidman, LLP billed the Company as set forth in the table below for professional services rendered for the audit of the Company's annual financial statements for the years ended December 31, 2004 and 2003 (reaudit) and for the reviews of the Company's quarterly financial statements included in the Company's Quarterly Reports on Form 10-Q for such periods and for work on other SEC filings. BDO Seidman, LLP provided non-audit services for the Company during 2004 as follows (1) the preparation of current and amended corporate tax returns, (2) tax planning and advice for mergers and acquisitions, and (3) tax compliance consultations. All amounts billed by BDO Seidman, LLP were for work performed subsequent to its engagement during 2004 and are reflected in the "Fiscal 2004" column below. KPMG LLP, the predecessor auditor, billed the Company for the audit of the Company's annual financial statements for the year ended December 31, 2003 and other audit services, as set forth in the "Fiscal 2003" column below. KPMG LLP did not provide any non-audit services for the Company during 2003.

	Fiscal 2004	Fiscal 2003
Audit Fees	$691,585	$379,000
Tax Services	$ 69,200	–0–
All Other Services	–0–	–0–

Policy on Audit Committee Pre-Approval of Audit and Non-Audit Services

The Audit Committee has established a policy for the pre-approval of audit and non-audit services performed for the Company by the independent registered public accounting firm, which also specifies the types of services that the independent registered public accounting firm may and may not provide to the Company. The policy provides for general pre-approval of services and specific case-by-case approval of certain services. The services that are pre-approved include audit services and audit-related services such as due diligence services pertaining to potential business acquisitions and dispositions, tax services and may also include other services. The term of any pre-approval is 12 months and is generally subject to certain specific budgeted amounts or ratios as determined by the Committee. The Committee may revise the list of general pre-approved services from time to time based on subsequent determinations. Unless a type of service has received general pre-approval, it will require specific pre-approval by the Audit Committee. Any proposed services which were addressed in the pre-approval, but exceed pre-approved cost levels or budgeted amounts will also require specific pre-approval by the Committee. The Audit Committee does not delegate its responsibilities concerning pre-approval of services to management. The independent registered public accounting firm and management are required to periodically report to the Audit Committee regarding the extent of services provided by the independent registered public accounting firm in accordance with this pre-approval, and the fees for services performed to date.

PROPOSAL IV

Other Business

Management does not intend to bring any business before the meeting other than the election of a director, the proposed Amendment to the Charter and appointment of BDO Seidman, LLP referred to in the accompanying notice. No other matter or nomination for director has been timely submitted to the Company in accordance with the provisions of the Company's Bylaws. If, however, any other matters properly come before the meeting, it is intended that the persons named in the accompanying proxy will vote pursuant to discretionary authority granted in the proxy in accordance with their best judgment on such matters. The discretionary authority includes matters that the Board of Directors does not know are to be presented at the meeting by others.

Additional Information

Stockholder Communications — The Company's Board of Directors has provided for a process for security holders to send communications to the Board of Directors. Any security holder can send communications to the Board by mail as follows:

Board of Directors of Edge Petroleum Corporation
c/o Corporate Secretary
1301 Travis, Suite 2000
Houston, Texas 77002

All security-holder communications will be relayed to all Board members. Communications from an officer or director of the Company will not be viewed as security holder communications for purposes of the procedure. Communications from an employee or agent of the Company will be viewed as security holder communications for purposes of the procedure only if those communications are made solely in such employee's or agent's capacity as a security holder.

Stockholder Proposals — The Company's Bylaws require written notice to be delivered to the Secretary of the Company by a stockholder:

- in the event of business to be brought by a stockholder before an annual meeting, not less than 120 days prior to the anniversary date of the immediately preceding annual meeting of stockholders of the Company (with certain exceptions if the date of the annual meeting is different by more than specified amounts from the anniversary date), and
- in the event of nominations of persons for election to the board of directors by any stockholder,
- with respect to an election to be held at the annual meeting of stockholders, not less than 120 days prior to the anniversary date of the immediately preceding annual meeting of stockholders of the Company (with certain exceptions if the date of the annual meeting is different by more than specified amounts from the anniversary date), and
- with respect to an election to be held at a special meeting of stockholders for the election of directors, not later than the close of business on the tenth day following the day on which notice of the date of the special meeting was mailed to stockholders or public disclosure of the date of the special meeting was made, whichever first occurs.

If the date of the 2006 annual meeting of stockholders is not more than 30 days before, nor more than 60 days after, the first anniversary of the date of the 2005 Annual Meeting, stockholders who wish to nominate directors or to bring business before the 2006 Annual Meeting of stockholders must notify the Company no later than December 28, 2005. Such notice must set forth specific information regarding such stockholder and such business or director nominee, as described in the Company's Bylaws. The Company's Bylaws also provide for certain procedures to be followed by stockholders in nominating persons for election to the Board of Directors of the Company.

Compliance with the above will generally result in a proposal that is proper business (or director nomination) being eligible to be brought before the stockholders for voting upon at the annual meeting. However, compliance with these requirements does not mean that the Company is required to include the proposal in the proxy solicitation material that the Company prepares and distributes. In order for a stockholder to require that a proposal be included by the Company in its proxy statement and proxy card, the stockholder must satisfy the requirements of Rule 14a-8 under the Securities Exchange Act of 1934, as amended, in addition to the requirements of the Bylaws. Rule 14a-8 addresses when a company must include a stockholder's proposal in its proxy statement and identify the proposal in its form of proxy when the company holds an annual or special meeting of stockholders. Under Rule 14a-8, proposals that stockholders intend to have included in the Company's proxy statement and form of proxy for the 2006 Annual Meeting of stockholders must be received by the Company no later than November 24, 2005. However, if the date of the 2006 Annual Meeting of stockholders changes by more than 30 days from the first anniversary of the date of the 2005 Annual Meeting of stockholders, the deadline by which proposals must be received is a reasonable time before the Company begins to print and mail its proxy materials, which deadline will be set forth in a quarterly report on Form 10-Q or will otherwise be communicated to stockholders. Stockholder proposals must also be otherwise eligible for inclusion.

By Authorization of the Board of Directors

/s/ Robert C. Thomas

Robert C. Thomas
Vice President, General Counsel & Corporate Secretary

March 24, 2005

EDGE PETROLEUM CORPORATION ANNUAL MEETING OF STOCKHOLDERS

10:00 a.m., April 27, 2005

Doubletree Hotel
400 Dallas Street
Houston, Texas 77002

ADVANCE REGISTRATION

Attendance at the Annual Meeting is limited to Edge stock owners (or a designated representative or proxy) with proof of ownership and members of their immediate family and employees and guests of the Company. In order to attend as a stockholder or immediate family member, you or your family member must be a stockholder of record as of March 17, 2005, or you must provide a copy of a brokerage statement or other evidence of beneficial ownership showing your ownership of Common Stock on March 17, 2005. Attendees may register at the door on the day of the meeting; however, advance registration for the Edge Annual Meeting will expedite your entry into the meeting.

- If you hold your Edge shares directly with the Company and you/or a member of your immediate family plan to attend the Annual Meeting, please follow the Advance Registration instructions on the top portion of your Proxy Form, which was included in the mailing from the Company.
- If you desire to appoint a person to attend the meeting and vote your shares on your behalf, you may do so by inserting that person's name in the blank space provided at the top of your Proxy Form. Such person need not be a stockholder of the Company. At the meeting, such person must present to the inspector of elections a proxy signed by the stockholder, or by his or her attorney authorized in writing, as his or her name appears on our register of stockholders. If the stockholder is a corporation, the proxy must be executed by a duly authorized officer or attorney thereof.
- If your Edge shares are held for you in a brokerage, bank or other institutional account and you wish to *register in advance*, please direct your request to:

Edge Petroleum Corporation
1301 Travis, Suite 2000
Houston, Texas 77002
Attention: Corporate Secretary

Please include the following in your request:

- Your name and complete mailing address;
- The name(s) of any immediate family members who will accompany you; and
- Proof that you own Edge shares (e.g., a photocopy of a brokerage or other account statement).

No cameras, video recorders or tape recorders of any type will be permitted in the meeting. We realize that many cellular phones have built-in cameras, and while these phones may be brought into the meeting venue, the camera function may not be used at any time. Inappropriate or disorderly behavior will result in expulsion from the meeting.