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SEC Mail Processing Section
APR 23 2007

Growth

Execution

✓ Opportunity

✓ Strategy

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APR 30 2007
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FINANCIAL

FINANCIAL HIGHLIGHTS

	2006	2005	2004
Financial Data (000s):			
Revenue	**$ 129,744**	$ 121,183	$ 64,505
Operating Income (Loss)	**$ (60,323)**	$ 51,461	$ 23,821
Net Income (Loss)	**$ (41,261)**	$ 33,358	$ 15,129
Total Assets	**$ 321,657**	$ 343,380	$ 190,990
Current Assets	**$ 31,940**	$ 36,701	$ 24,866
Current Liabilities	**$ 21,778**	$ 26,164	$ 15,909
Notes Payable	**$ 129,000**	$ 85,000	$ 20,000
Shareholders' Equity	**$ 156,052**	$ 191,755	$ 150,467

Operating Data:			
Total Proved Reserves (Bcfe)	**102**	103	89
Total Production (MMcfe)	**17,251**	16,384	12,093
PV-10 (000s)[1]	**$ 233,206**	$ 343,790	$ 216,871
Reserve Replacement[2]	**97%**	184%	308%

[1] See page 7 of the Annual Report on Form 10-K for a reconciliation to standardized measure of discounted future net cash flows and other information.
[2] See page 8 of the Annual Report on Form 10-K for more information.

Edge Petroleum is a rapidly growing Houston-based independent energy company engaged in the exploration, development, acquisition and production of natural gas, natural gas liquids and crude oil with operations focused onshore in the United States, primarily along the Gulf Coast and Permian Basin of Texas and New Mexico. In January of 2007, Edge closed a large, transforming acquisition of oil and gas properties which the company believes has significant future potential. On a pro forma basis for this acquisition, reserves at December 31, 2006 would have been approximately 225 Bcfe, an increase of 120% over the actual reported year-end 2006 reserves and the reserve replacement ratio would have been approximately 600%.

Our strategies encompass the following elements:

- Focus our exploration and development activities primarily on natural gas
- Aggressively exploit our acreage position in successful trends
- Add new exploration and exploitation plays in our core areas and expand into new core areas if warranted
- Pursue acquisitions that compliment our existing operations and have upside potential
- Pursue partnership/alliances that provide a means to grow our asset base
- Continue to apply the most appropriate technology in an effective manner
- Ensure that constant attention is given to managing cost effectively
- Divest our non-strategic and/or underperforming assets
- Intelligent and timely hedging to mitigate the adverse impact commodity price volatility can have on cash flow and our ability to continue expanding our program
- Maintain a competent workforce and provide recognition and compensation for sustained effort and outstanding performance

Corporate Profile – Pro Forma for January 2007 Acquisition

Natural gas focus

- 90% of pro forma reserves at 12/31/06 were natural gas and natural gas liquids
- 83% of pro forma year-end production was natural gas and natural gas liquids

Geographically-focused asset base

- Domestic, onshore Gulf Coast concentration
- 86% of pro forma reserves are in the onshore Texas Gulf Coast

Track record of successful operations

- Three-year compounded annual growth rate in reserves of 17%
- Three-year compounded annual growth rate in production of 29%
- January 2007 acquisition increased proved reserves 120% and average daily production by 65%
- Three-year apparent drilling success rate of 87%

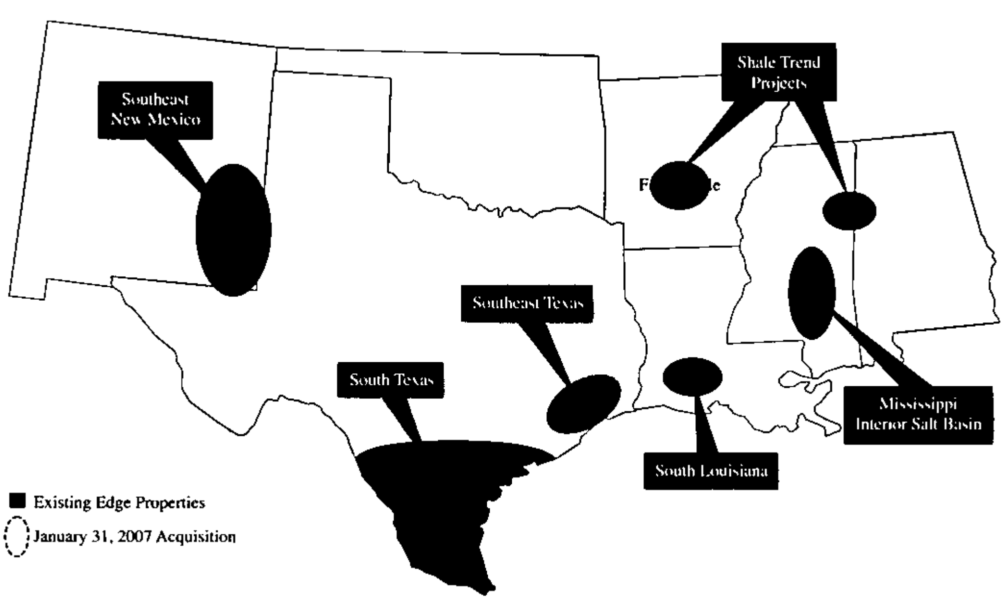
Balanced inventory of development and exploration prospects

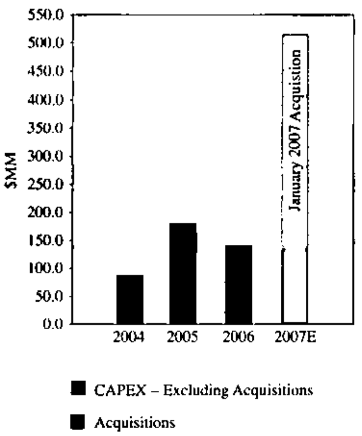
- Plan to drill 80–90 wells in 2007, an increase of 55–75% over 2006
- 2007 capital expenditures allocated 80% to new reserve additions via the drill bit
- Net undeveloped leasehold and option acreage totals more than 160,000 acres

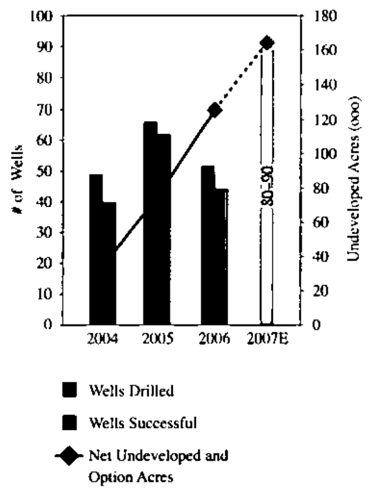
Value Drivers

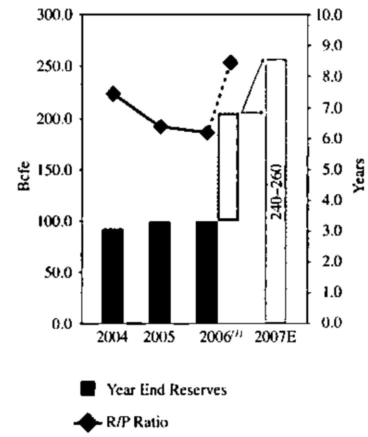
- Reserve and production growth in a cost effective manner from a significantly expanded portfolio of investment opportunities

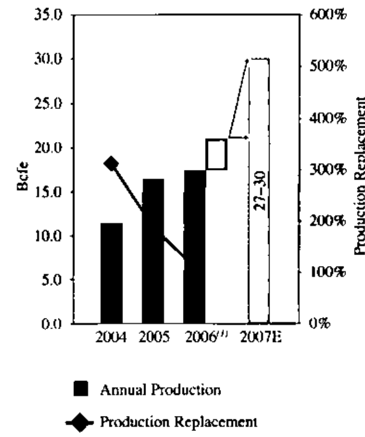
Focus Areas











- Capital expenditures have grown steadily, up 90% since 2004, before acquisitions.
- Capital expenditures for 2007, excluding acquisitions, are currently forecast to be approximately $140 million, up over 33% from 2006.
- Completed a $390 million acquisition in January 2007, representing the largest acquisition in company history, transforming the company in physical and fiscal size, establishing a new base from which to grow.
- 2007 capital program, excluding acquisitions, is expected to be funded from internally generated cash flow.

- Average apparent drilling success rate since 2004 of 87%.
- Plan to drill 80–90 wells in 2007, an increase over 2006 that is expected to range from 55% to 75%.
- Continued to add undeveloped leasehold and option acreage which is expected to provide opportunities for growth.
- Focus on a balanced program aimed at adding new reserves in a cost effective manner.

- Three year compounded average growth in net proved reserves of 17%.
- January 2007 acquisition increased pro forma year-end net proved reserves by 120%.
- Natural gas and natural gas liquids comprise 90% of the pro forma net proved reserves.
- R/P ratio, as a result of the January 2007 acquisition, has increased from approximately 6 to 9 years.
- Production replacement with new reserves in 2007 is forecast to be in the range of 155%–215%.

(1) 2006 results show the pro forma impact of the January 2007 acquisition as if it had occurred on 12/31/06.

- 29% compounded annual growth rate in production since 2004.
- Pro forma for the January 2007 acquisition, production replacement would have increased from 97% to slightly over 600%.
- Production for 2007 is forecast to increase in a range of 55%–75% over 2006 stand alone production of 17.3 Bcfe.
- 2007 production is forecast to increase in the range of 15%–35% over the 2006 pro forma production of 23.4 Bcfe.

(1) 2006 results show the pro forma impact of the January 2007 acquisition as if it had occurred on 12/31/06.

JANUARY 2007 ACQUISITION DETAIL

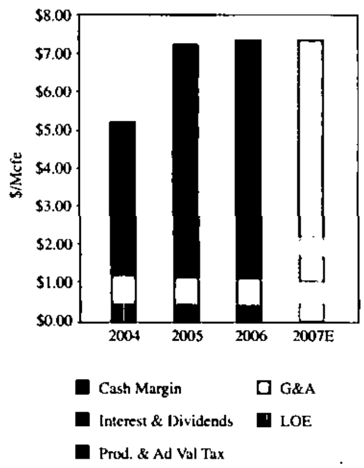
On January 31, 2007, Edge completed the largest acquisition in its history. The acquisition attributes are:

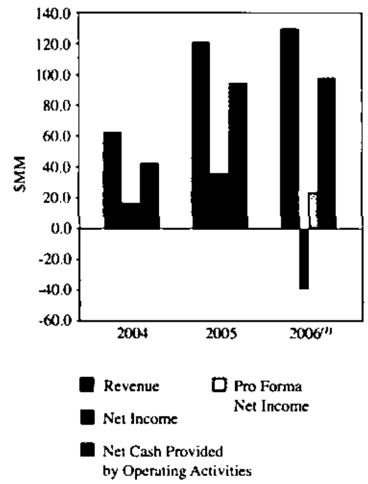
- Net proved reserves of 123 Bcfe as of January 1, 2007 in 23 active fields in south and southeast Texas, which increased our net total proved reserves 120% to 225 Bcfe.
- New property base is essentially an overlay with our onshore Texas Gulf Coast core areas.
- Provides opportunity for a significant increase in annual production above the 2006 pro forma production of 23.4 Bcfe by adding compression and exploiting the development inventory.
- R/P ratio for the acquired assets of 10 years increases our ratio from approximately 6 to 9 years.
- The acquired assets are greater than 90% operated, increasing our overall operated percentage to 68%, giving us more control over timing and efficiencies of operations.
- Balanced investment portfolio on a risk-reward basis that provides the opportunity for significant physical and fiscal growth in 2007 and beyond.

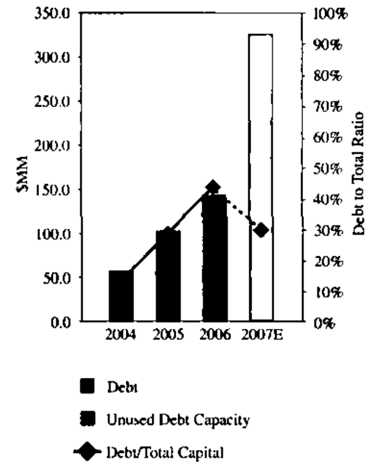
PROVED RESERVE IMPACT FROM JANUARY 2007 ACQUISITION

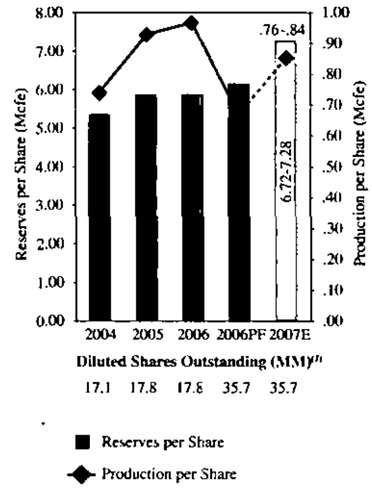
As of December 31, 2006	Edge				Pro forma(1)			
	Estimate Proved Reserves (Bcfe)	Natural Gas	Proved Developed	Estimate of Prod. Operated	Estimate Proved Reserves (Bcfe)	Natural Gas	Proved Developed	Estimate of Prod. Operated
South Texas	71	78%	74%	34%	163	79%	71%	58%
Southeast Texas	–	–	–	–	31	83%	47%	97%
Southeast New Mexico	7	44%	85%	91%	7	44%	85%	91%
South Louisiana	9	77%	100%	31%	9	77%	100%	31%
Mississippi Salt Basin	15	71%	78%	90%	15	71%	78%	90%
Total	102	75%	77%	46%	225	78%	70%	68%

(1) Pro forma assumes the January 31, 2007 acquisition was effective December 31, 2006









- G&A remained relatively flat from 2004 to 2006 on a unit of production basis.
- LOE increased 27% from 2004 to 2005 while remaining flat from 2005 to 2006, measured on a unit of production basis.
- On a unit of production basis, both G&A and LOE are forecast to decline in 2007.
- Production and ad valorem taxes, a function of revenue, have steadily increased since 2004. These taxes are forecast to increase again in 2007.
- Interest and dividends were minimal in 2004 and 2005, but increased in 2006 as acquisitions were funded with available borrowing capacity. Increased interest and dividends are forecast for 2007 associated with new debt and issuance of convertible preferred stock for the January 2007 acquisition.
- 2005-2006 cash margins increased to over $5.00 per Mcfe, well above the 2004 level of $3.88 per Mcfe.
- 2007 cash margins are forecast to be above $5.00 per Mcfe as the company continues its focus on cost management.

- Revenue has grown steadily with our increased production, strong commodity prices and effective price risk management programs.
- Third quarter 2006 non-cash property impairment impacted net income.
- Cash flow from operating activities reached a record level of $97.4 million in 2006.
- Our growing cash flow has allowed us to continue expanding our capital spending program year over year.

(1) Pro forma net income excludes the impact of unrealized derivative activity and the non-cash impairment of oil and natural gas properties.

- Funded recent acquisitions from a new $320 million credit line and concurrent equity offerings of common and convertible preferred stock for proceeds of $278 million.
- $85 million of unused borrowing capacity at February 28, 2007 and a debt to total capital ratio in the mid-30% level.
- The capital structure, post acquisition, provides significant financial flexibility to execute the approved program.

- Production per share grew about 30% from 2004–2005 and slightly more than 5% from 2005-2006.
- From 2004–2005, reserves per share increased about 11% then declined less than 1% from 2005–2006.
- Pro forma for the January 2007 acquisition, production per share is lower because of the higher percentage of undeveloped reserves in the acquired portfolio.
- Production growth in 2007 is forecast, on a per share basis, to be in the range of 5%–15%.
- Reserve growth in 2007 is forecast, on a per share basis, to be in the range of 15%–30%.

(1) Diluted weighted average common shares outstanding assuming preferred shares converted to common at a conversion ratio of 3.0193 to 1. Diluted shares used in the 2004 calculation include 3.5 million shares issued on December 31, 2004.

Reconciliation of Non-GAAP Measures (Cash Margin and Pro Forma Net Income)

Per Mcfe Analysis - $/Mcfe	2004	2005	2006	2007E
Revenue (after effect of hedging)	$ 5.33	$ 7.40	$ 7.52	$ 7.41
LOE	$ 0.41	$ 0.52	$ 0.53	$ 0.50
Production & Ad Valorem Taxes	$ 0.36	$ 0.52	$ 0.53	$ 0.60
G&A	$ 0.65	$ 0.60	$ 0.68	$ 0.53
Net Interest & Dividends	$ 0.02	$ 0.01	$ 0.14	$ 0.64
Total Expenses	$ 1.44	$ 1.63	$ 1.88	$ 2.27
Cash Margin	$ 3.89	$ 5.77	$ 5.64	$ 5.14

Pro forma Net Income	2004	2005	2006
Net income (loss) as reported	$ 15,129	$ 33,358	$ (41,261)
Add: Unrealized hedge activity	$ 564	$ (720)	$ (5,031)
FIN 44	$ 1,136	$ 1,628	$ –
Impairment	$ –	$ –	$ 96,942
Subtotal	$ 1,700	$ 908	$ 91,911
Tax impact	$ (595)	$ (318)	$ (32,169)
Net adjustment	$ 1,105	$ 590	$ 59,742
Pro forma Net Income	$ 16,234	$ 33,948	$ 18,481

Our Company exited 2005 having established a record level of production and reserves for the fourth year in a row and our expectations were that 2006 would show similar results. Although we achieved moderate production growth in 2006, up 5% over 2005, our reserves declined slightly from the prior year. These results fell short of the operational and financial targets we expected to reach in 2006. In part, our shortfall was due to the fact that we drilled fewer wells than planned, particularly in our non-operated Chapman Ranch and Encinitas areas where we expected to add reserves and production in 2006. In addition, natural gas prices fell throughout the year, causing us to record a pre-tax, non-cash ceiling test write-down of $96.9 million and a negative reserve revision of 2.4 Bcfe due to falling prices. The falling gas prices and lower production volumes than we expected reduced cash flow below our pre-acquisition capital expenditure level resulting in an increase in debt versus our original year-end 2006 expectations.

Nevertheless, we were still able to close on two acquisitions in 2006 utilizing our unused borrowing capacity. The Chapman Ranch acquisition, the larger of the two transactions, has given us the operating control that will enable us to now move forward in a timely manner with the exploitation of this attractive asset as well as the exploration potential we have identified in the surrounding area.

In addition to the two year-end acquisitions, we identified and negotiated an acquisition of properties in south and southeast Texas owned by a private company which we were able to complete successfully on January 31, 2007. We believe this transaction is truly a transforming event for Edge in that it provides a step change in our reserves and production while exposing us to a wide array of new exploration and development opportunities. Because the acquired properties are essentially an overlay to our onshore Texas Gulf Coast core areas, we believe we will begin extracting value from these new properties as soon as we are able to integrate them into our portfolio.

Prior to closing, our creditors approved a new four-year revolving credit line of $320 million for the Company which replaced our existing $140 million revolver. Also, we were able to complete concurrent offerings of common stock and convertible preferred stock that raised a net $278 million. As a result, we were able to fund over $400 million of late 2006 and early 2007 acquisitions with these two transactions leaving us with the financial flexibility to execute a record capital expenditure program in 2007 and to continue aggressively pursuing other investment opportunities that we believe can add value to the Company and ultimately to our shareholders.

Our 2007 capital expenditure program for wells, land and seismic and other related activities will be at a record level of approximately $140 million, excluding acquisitions, and we expect to fund this program through internal cash flow. Our plan includes spending approximately $100 million for the drilling of 80 to 90 wells, which is a significant increase over the number of wells that were drilled in 2006. Although we have a sizable inventory of proven undeveloped (PUD) locations, our 2007 drilling program includes only 20% PUD locations versus 65% in 2006. Our emphasis in 2007 will be on growing our reserves organically via the drill bit. At the present time, our prospect inventory has an estimated net unrisked resource potential of approximately 1 Tcfe and we are continuing to make investments in undeveloped properties and new seismic that we expect will result in our identifying attractive opportunities that we will want to acquire.

We project our full-year 2007 production to be in the range of 27 to 30 Bcfe, up significantly from our 2006 stand alone level of 17.3 Bcfe as well as on a pro forma basis with our recent acquisition of 23.4 Bcfe for the full year.

We are not at this time experiencing any problems accessing drilling rigs or other related oil field services and we are beginning to see costs for these services flatten or even coming down to some degree.

We have expanded our workforce from 68 at year end to 78 at the present time and intend to supplement our staff with consultants when we see the need to do so.

Our challenge now is to extract the value that we see in our existing property base and in the properties we have recently acquired. We believe our personnel possess the experience and expertise to effectively execute our business plan to achieve the performance objectives and goals that have been established for the Company in 2007 and beyond.

Sincerely,

John W. Elias

John W. Elias
Chairman, President & CEO

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, 2006
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 (State or other jurisdiction of incorporation or organization)	76-0511037 (I.R.S. Employer Identification No.)
1301 Travis, Suite 2000 Houston, Texas (Address of principal executive offices)	77002 (Zip code)

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

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

Title of each class	Name of each exchange on which registered
Common Stock, Par Value $0.01 Per Share	NASDAQ
5.75% Series A Cumulative Convertible Perpetual Preferred Stock, Par Value $0.01 Per Share	NASDAQ

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
☐Yes ☑ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
☐Yes ☑ No

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and larger accelerated filer" in Rule 12b-2 of the Exchange Act.:
☐ Large accelerated filer ☑Accelerated Filer ☐ Non-accelerated filer

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ☐Yes ☑ No

As of June 30, 2006, the aggregate market value of the voting stock held by non-affiliates of the registrant was $334.3 million (based on a value of $19.98 per share, the closing price of the Common Stock as quoted by NASDAQ Global Select Market on such date).

As of March 8, 2007, 28,383,455 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 2007 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", "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 Annual Report on Form 10-K 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, 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, 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 expressions 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 *ITEM 1A. "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 us or to persons acting on our behalf are expressly qualified in their entirety by reference to these risks and uncertainties.

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 Relations - SEC Filings," 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 Securities and Exchange Commission ("SEC"). The SEC also maintains a website at www.sec.gov that contains reports, proxy statements and other information regarding SEC registrants, including us.

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. 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 and strategy. We believe the continuation of this disciplined business model and strategy will result in continued growth in reserves, production and financial strength and flexibility.

Recent Developments & Accomplishments

Overview

At year-end 2006, our net proved reserves were 102.1 Bcfe, comprised of 76.1 billion cubic feet of natural gas, 1.9 million barrels of natural gas liquids and 2.4 million barrels of crude oil and condensate. Natural gas and natural gas liquids accounted for approximately 86% of those proved reserves. Approximately 77% of total proved reserves were developed as of year-end 2006 and they were all located onshore, in the United States. During 2006, we focused on developing and exploiting assets in south Texas, our largest core area. Our 2006 drilling program did not meet our expectations as it was adversely impacted by drilling delays on our nonoperated properties, mainly at the Chapman Ranch Field, shortages of oilfield services and qualified personnel, and the drilling of a larger than originally planned number of proved undeveloped locations. These events, along with falling natural gas prices, the disappointment of drilling a total of nine dry holes, and the deferment of portions of our drilling program targeting potential new reserves, including the Chapman Ranch Field properties, resulted in a slight decrease in our estimated proved reserves at December 31, 2006 of 102.1 Bcfe compared to the prior year of 102.8 Bcfe. Despite these factors, we were able to drill 52 wells with an apparent success rate of 83% in 2006. As described below, in December 2006, we completed an acquisition involving additional working interests and operatorship in the Chapman Ranch Field, where we already owned working interests as a result of two acquisitions late in 2005. Obtaining operatorship strategically positions us in 2007 and beyond to develop and exploit what we believe is an essential asset in our south Texas portfolio.

Kerr-McGee Acquisition

On December 28, 2006, we completed an acquisition of certain working interests in the Chapman Ranch Field from Kerr-McGee Oil and Gas Onshore, L.P. ("Kerr-McGee"), a wholly-owned subsidiary of Anadarko Petroleum Corporation, for approximately $25 million (the "Kerr-McGee acquisition"). In late 2005, we acquired working interests in this field, including interests in several producing wells, ranging from approximately 44% to 50%. In the Kerr-McGee acquisition, we acquired an additional 44% to 50% working interest in the same wells in the field, and acquired two additional wells, bringing our working interests in those Chapman Ranch properties, including a total of nine producing wells, to 88% to 100%. As of December 31, 2006, the Kerr-McGee assets had approximately 9.0 Bcfe of proved reserves, of which approximately 30% were proved developed. We financed the acquisition with borrowings under our then-existing credit facility.

Smith Acquisition

On January 31, 2007, we completed the purchase of certain oil and natural gas properties located in 13 counties in south and southeast Texas and other associated assets from Smith Production Inc. ("Smith"). We paid approximately $389.8 million for these assets ("Smith assets"). Although a 2007 event for us, as of December 31, 2006, the Smith assets contained approximately 123.0 Bcfe of proved reserves, which were 81% natural gas and 64% proved developed. In total, the Smith assets include approximately 150 gross producing wells (74 net) and an ownership interest in approximately 17,000 gross (12,250 net) developed acres and 56,000 gross (16,000 net) undeveloped acres of leasehold, all as of December 31, 2006.

In addition to the properties and related acreage, we acquired from Smith certain gathering facilities and ownership of approximately 13 miles of natural gas gathering pipelines and related infrastructure serving certain producing assets in southeast Texas. The pipeline system transports our natural gas as well as third-party natural gas.

We also acquired 25% of Smith's option and leasehold rights in an approximate 95 square mile 3-D exploration area with approximately 30,000 gross acres of leases and options located in the Mission project area in Hidalgo County in south Texas, with a primary focus on the Vicksburg formation. We acquired a 12.5% working interest in an approximate 160 square mile 3-D exploration area with approximately 55,000 gross acres of leases and options located in the Yates Ranch/Hostetter project area in McMullen and Duval Counties in south Texas. The 160 mile 3-D area increases our exposure to the Middle and Deep Wilcox trend. Furthermore, this venture allows us to participate in a proposed additional 3-D shoot covering approximately 120 square miles near the Yates Ranch within the Wilcox trend. We also acquired 25% of Smith's option and leasehold rights in an approximate 105 square mile 3-D exploration area with approximately 60,000 gross acres of leases and options in Newton County in southeast Texas and Beauregard Parish in Louisiana with a focus on prospects in the Frio, Yegua and Wilcox formations at depths ranging between 4,000 and 10,000 feet.

Public Offerings

In January 2007, we completed concurrent public offerings of 10,925,000 shares of our common stock for net proceeds of approximately $138.1 million and 2,875,000 shares of our 5.75% Series A cumulative convertible perpetual preferred stock for net proceeds of approximately $138.6 million. We used the net proceeds from these offerings, along with borrowings under our current credit facility, to finance the Smith acquisition and to repay our prior credit facility.

Strategy

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

1. *Grow reserves through acquisitions and 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 2006, we drilled 52 wells (28.93 net), primarily in Texas, with 43 (23.40 net) of those wells completed as productive for an apparent success rate of approximately 83%. This drilling program, along with our acquisition of certain oil and gas assets on the Chapman Ranch Field, helped us to replace 97% of our production (see "Oil and Natural Gas Reserve Replacement"). Over the last three years, we drilled 166 wells (91.29 net). Of the drilled wells, 145 gross (78.27 net) have been completed as apparent successes, for a success rate of approximately 87%. As a result of our acquisitions and drilling program, we have grown production and proved reserves since December 31, 2004. Production has grown from 12.1 Bcfe at December 31, 2004 to 17.3 Bcfe at December 31, 2006, an increase of approximately 43%. Also, we have grown proved reserves from approximately 89.1 Bcfe at year-end 2004 to 102.1 Bcfe at December 31, 2006. We expect our drilling program for 2007 to be focused primarily in south Texas, and to a lesser extent in the Mississippi Salt Basin, southeast New Mexico and the Fayetteville Shale in Arkansas. We expect to drill between 80 and 90 wells (37 and 42 net, respectively) in 2007 and we estimate capital spending for the year to be approximately $140 million. In addition, we have a contingent drilling program that could add wells and costs to this estimate.

2. *Seek acquisitions that we believe have upside potential.* We seek acquisitions of producing properties that typically have exploration or exploitation upside potential. As illustrated by the Kerr-McGee acquisition and the Smith acquisition, we primarily seek properties in our existing core areas or as a means to establish new core areas. We continue to work diligently to identify and evaluate acquisition opportunities with the goal of implementing those that we believe would fit our strategic plan and add stockholder value.

3. *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 the areas in which we operate. 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.

4. *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 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.

5. *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 target range of 30% to 40% for our total debt-to-capital ratio. At December 31, 2006, our debt-to-total capital ratio was 45.3%, resulting from the use of debt to finance our acquisition programs in 2005 and 2006. Subsequent to December 31, 2006, we issued 10,925,000 shares of common stock and 2,875,000 shares of 5.75% Series A cumulative convertible perpetual preferred stock, which reduced our total debt-to-capital ratio.

   We try to fund most of our ongoing capital expenditures using 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. Over the past several years, we have worked diligently to control our operating and overhead costs and instituted a formal, disciplined budgeting process.

6. *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 February 28, 2007, our directors and employees, including executive officers, owned or had options to acquire an aggregate of approximately 7% of our outstanding common stock.

Employees

As of March 9, 2007, we had 75 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

We lease executive and corporate office space located in Travis Tower in Houston, Texas.

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 net cash flows related to such reserves as of December 31, 2006. We engaged Ryder Scott Company, L.P. ("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, 2006. 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 thirteen years and WDVG has independently reviewed the reserves we acquired from Contango Oil and Gas Company late in 2004 for the past five years. In estimating the reserve quantities that are economically recoverable, Ryder Scott and WDVG used oil and natural gas prices in effect at December 31, 2006 and estimated development and production costs that were in effect during December 2006 without giving effect to hedging activities. In accordance with 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, 2006, see the summaries of the reserve reports of Ryder Scott and WDVG included as exhibits to this Form 10-K (respectively, the "Ryder Scott Report" and the

"WDVG Report"). In accordance with Statement of Financial Accounting Standards ("SFAS") No. 69, *Disclosures About Oil and Natural Gas Producing Activities,* the present value of estimated future net revenues after income taxes was prepared using constant prices as of the calculation date, discounted at 10% per annum, 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 21 to our consolidated financial statements. See also *ITEM 1A. "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 as of December 31, 2006		
	Developed (1)	**Undeveloped (2)**	**Total**
Oil and condensate (MBbls)(3)	3,158	1,167	4,325
Natural gas (MMcf)	60,163	15,984	76,147
Total MMcfe	79,114	22,984	102,098
In thousands:			
Estimated future net revenue before income taxes	$ 351,433	$ 57,857	$ 409,290
Present value of estimated future net revenue before income taxes (discounted 10% per annum) (4)	$ 240,971	$ 30,545	$ 271,516
Future income taxes (discounted 10% per annum)	(35,116)	(3,194)	(38,310)
Standardized measure of discounted future net cash flows	$ 205,855	$ 27,351	$ 233,206

(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, 2006, which were $5.62 per MMbtu of natural gas and $61.06 per Bbl of oil. Management believes that the presentation of the present value of future net cash flows attributable to estimated proved reserves, discounted at 10% per annum (the "PV-10 Value"), may be considered a non-GAAP financial measure as defined in Item 10(e) of Regulation S-K, therefore the Company has included this reconciliation of the measure to the most directly comparable GAAP financial measure (Standardized measure of discounted future net cash flows). Management believes that the presentation of PV-10 Value provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because many factors that are unique to each individual company may impact the amount of future income taxes to be paid, the use of the pre-tax measure provides greater comparability when evaluating companies. It is relevant and useful to investors for evaluating the relative monetary significance of the Company's oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of the Company's reserves to other companies. Management also uses this pre-tax measure when assessing the potential return on investment related to its oil and natural gas properties and in evaluating acquisition candidates. The PV-10 Value is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of the estimated oil and natural gas reserves owned by the Company. PV-10 Value should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

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, 2006, adjusted for basis and quality differentials. 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, 2006. 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. In particular, natural gas prices at December 31, 2006 were significantly lower than natural gas prices in effect at the previous year-end. The average natural gas price used in the December 31, 2005 estimation of pre-tax future net cash flows of proved reserves, using a 10% discount rate ("PV10"), was $10.05 per MMBtu of gas, which is considerably higher than the $5.62 per MMBtu used to calculate the PV10 at December 31, 2006. Decreases in the assumed commodity prices result in decreases in estimated future net revenue as well as in estimated reserves.

Oil and Natural Gas Reserve Replacement

Finding and developing sufficient amounts of natural gas and crude oil reserves at economical costs are critical to our long-term success. Our business, as with other extractive businesses, is a depleting one in which each gas equivalent unit produced must be replaced or our asset base and ability to generate revenues in the future 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. We use the reserve replacement ratio, as defined below, as an indicator of our ability to replenish annual production volumes and grow our reserves, thereby providing some information on the sources of future production and income. We believe 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, acquisitions, 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 *ITEM 1A. "RISK FACTORS"*). The values for these reserve additions and production are derived directly from the proved reserves table in Note 21 to our consolidated financial statements. Accordingly, we do not use unproved reserve quantities. 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, the percentage of reserves that were developed was 77%, 74% and 75% for the years ended December 31, 2006, 2005 and 2004, respectively. Set forth below is our reserve replacement ratio for the periods indicated.

	For the Year Ended December 31,			
	2006	**2005**	**2004**	**Three Year Average**
Reserve Replacement Ratio	97%	184%	308%	184%

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 expenses associated with our sale of oil and natural gas for the periods indicated.

	Year Ended December 31,		
	2006	2005	2004
Production:			
Oil and condensate (MBbls)	345	324	215
Natural gas liquids (MBbls)	222	308	276
Natural gas (MMcf)	13,850	12,597	9,148
Natural gas equivalent (MMcfe)	17,251	16,384	12,093
Average sales price - before hedging and derivatives:			
Oil and condensate ($ per Bbl)	$ 63.10	$ 53.57	$ 39.77
Natural gas liquids ($ per Bbl)	25.52	18.45	15.83
Natural gas ($ per Mcf)	6.68	7.97	5.91
Natural gas equivalent ($ per Mcfe)	6.96	7.53	5.54
Average sales price - after hedging and derivatives:			
Oil and condensate ($ per Bbl)	$ 64.10	$ 50.36	$ 33.03
Natural gas liquids ($ per Bbl)	25.52	18.45	15.83
Natural gas ($ per Mcf)	7.36	7.87	5.80
Natural gas equivalent ($ per Mcfe)	7.52	7.40	5.33
Average oil and natural gas operating expenses ($ per Mcfe)(1)	$ 0.53	$ 0.52	$ 0.41
Average production and ad valorem taxes ($ per Mcfe)	$ 0.53	$ 0.52	$ 0.36

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

Exploration, Development and Acquisition Capital Expenditures

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

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Acquisition costs:			
Unproved properties	$ 21,661	$ 33,948	$ 12,163
Proved properties (1)	36,573	66,472	33,980
Exploration costs	17,898	20,426	8,297
Development costs	64,724	58,685	34,549
Subtotal	140,856	179,531	88,989
Asset retirement costs	416	436	278
Total costs incurred	$ 141,272	$ 179,967	$ 89,267

(1) Includes $17.8 million added to property acquired in the Cinco acquisition in 2005 associated with recording a deferred tax liability at the date of acquisition for taxable temporary differences existing at the purchase date in accordance with SFAS No. 109, *Accounting for Income Taxes*. This amount was adjusted to $16.8 million in 2006 as a result of the final purchase price adjustment for the Cinco acquisition. See Notes 6 and 15 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 periods indicated. 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.

	Year Ended December 31,					
	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Exploratory:						
Productive	13	5.12	16	6.44	5	2.35
Non-productive	5	2.66	1	0.75	5	2.50
Total	18	7.78	17	7.19	10	4.85
Development:						
Productive	30	18.28	46	26.51	35	19.33
Non-productive	4	2.87	2	1.75	4	2.73
Total	34	21.15	48	28.26	39	22.06
Grand Total	52	28.93	65	35.45	49	26.91
Success Ratio	**83%**	**81%**	**95%**	**93%**	**82%**	**81%**

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, 2006.

	Company-Operated		Non-Operated		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil	25	12.59	72	19.45	97	32.04
Natural gas	87	72.97	235	86.22	322	159.19
Total	112	85.56	307	105.67	419	191.23

Acreage Data

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of December 31, 2006. 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
Arkansas	--	--	5,448	4,629	5,448	4,629
Montana	--	--	12,446	9,329	12,446	9,329
Michigan	160	160	498	498	658	658
Alabama	750	47	--	--	750	47
Louisiana	1,906	470	236	126	2,142	596
New Mexico	7,328	2,281	92,687	17,555	100,015	19,836
Mississippi	10,262	3,220	55,641	43,833	65,903	47,053
Texas	60,139	25,051	14,412	5,918	74,551	30,969
Total	80,545	31,229	181,368	81,888	261,913	113,117

Leases covering approximately 15,404 gross (11,793 net), 24,716 gross (19,984 net) and 17,248 gross (12,178 net) undeveloped acres are scheduled to expire in 2007, 2008 and 2009, 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 or other drilling or reworking operations are being continuously prosecuted.

The table above does not include 93,362 gross (41,785 net) undeveloped acres in Texas for which we have the option to acquire leases based upon a commitment of continuous drilling subject to the following:

Options Expire*	Gross Acres	Net Acres
2007	92,351	41,613
2008	1,011	172
Total	93,362	41,785

* This is an estimate of the expiration of our option to acquire leased acreage based on our current well and 3-D seismic acquisition schedule.

Core Areas of Operation

As of December 31, 2006, 70% of our proved reserves were in south Texas, 14% in Mississippi, 8% in New Mexico, and 8% in south Louisiana, Michigan, Alabama and Arkansas. During 2006, we added reserves and production through our drilling program, focused in south Texas, and our acquisition program.

The table below sets forth the gross and net number of our gas, oil and service wells in each of our core areas of operation as of December 31, 2006.

	Gas Wells		Oil Wells		Service Wells (1)	
	Gross	Net	Gross	Net	Gross	Net
Texas	289	145.27	42	17.24	4	1.90
Louisiana	6	1.16	--	--	3	0.64
Mississippi	9	5.44	25	5.00	4	1.57
Alabama	--	--	5	0.22	3	0.26
Michigan	1	1.00	--	--	--	--
New Mexico	17	6.32	25	9.58	--	--
Total	322	159.19	97	32.04	14	4.37

(1) Service wells are wells drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

Texas

As of December 31, 2006, we owned an interest in 74,551 gross (30,969 net) acres in south Texas. Our areas of focus in this region are predominantly in the Wilcox, Queen City, Vicksburg and Frio producing trends. As of December 31, 2006, we operated approximately 80 producing wells, which along with our 255 non-operated wells accounted for about 81% of our total net production in 2006. We drilled 33 wells during 2006 in Texas, 76% of which were an apparent success. The majority of our 2006 drilling activity took place in the Queen City project area. We drilled 21 apparently successful wells in the Queen City project area, one at Chapman Ranch and one at Encinitas. In 2007, we currently expect to drill 45 to 49 wells (23 to 25 net, respectively) in our core areas in Texas. The majority of these wells are planned in the Vicksburg, Frio, Wilcox and Queen City project areas.

South Louisiana

As of December 31, 2006, we owned an interest in 2,142 gross (596 net) acres in south Louisiana primarily located in Acadia, Calcasieu, Lafayette, St. Landry and Vermilion Parishes. As of December 31, 2006, we had an interest in 9 wells, none of which we operate. We did not drill any wells in south Louisiana in 2006 and we have no current plans to drill additional wells in this area in 2007. We did, however, acquire new properties in Louisiana in our Smith acquisition in 2007.

Mississippi Interior Salt Basin

As of December 31, 2006, we owned an interest in 65,903 gross (47,053 net) acres in the Mississippi Interior Salt Basin area, including undeveloped acreage in the Floyd Shale play. We acquired reserves and production in the Mississippi Interior Salt Basin in south central Mississippi as part of the 2003 merger with Miller Exploration

Company ("Miller"). The primary producing horizons in the Mississippi Interior Salt Basin around the Miller properties include the Hosston, Sligo, Rodessa and James Lime sections. As of December 31, 2006, we operated eleven producing wells in this area. Production from wells in the Mississippi Interior Salt Basin accounted for approximately 7% of our total net production in 2006. In 2006, we drilled one well (0.75 net) in this area. In 2007, we plan to drill 3 to 5 wells (2 to 4 net, respectively) in the Mississippi Interior Salt Basin.

Michigan

As of December 31, 2006, we owned 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. We operate this well which produces from the Trenton/Black River formation at approximately 3,000 feet and this well accounted for approximately 1% of our total net production in 2006. We have no plans for additional activity in Michigan in 2007 at this time.

Southeast New Mexico

We established a new core area in southeast New Mexico through an alliance with two private companies in 2003. As of December 31, 2006, we owned an interest in 100,015 gross (19,836 net) acres in this area that we earned through a drilling obligation we fulfilled during 2004 and 2005 and through subsequent purchases. The objectives in this area are shallow oil in the Yeso, San Andres, Queen and Grayburg formations, and deep natural gas in the Atoka and Morrow formations. Additional objectives are the Strawn, Cisco, Wolfcamp and Devonian formations. In 2006, we participated in the drilling of 16 gross (5.6 net) wells, of which 94% were apparent successes. Production from wells in the southeast New Mexico area represented approximately 10% of our total net production in 2006. During 2007, we anticipate drilling 10 to 12 wells (2 to 3 net, respectively) in southeast New Mexico.

Arkansas

As of December 31, 2006, we owned an interest in 5,448 gross (4,629 net) undeveloped acres in the Fayetteville Shale play in south central Arkansas. In 2006, we drilled two wells (0.9 net), both of which were apparently successful, although not yet producing. During 2007, we anticipate drilling 20 to 24 wells (6 to 8 net, respectively) in this area.

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 Notes 10 and 12 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.

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 to price fluctuations. While the use of these arrangements may 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 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. None of these instruments are used for trading purposes. All such derivative transactions provide for financial rather than physical settlement. On a quarterly basis, our management reviews all of our price-risk management transaction policies, including volumes, accounting treatment, types of instruments and counterparties. 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 continuously monitors 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 and *ITEM 7. "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS* – CRITICAL ACCOUNTING POLICIES AND ESTIMATES – DERIVATIVES AND HEDGING ACTIVITIES.").

All of these price-risk management transactions are considered derivative instruments and are accounted for in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (as amended). 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 and the cash flows resulting from settlement of these derivative transactions are classified in operating activities on the statement of cash flows. For those derivatives to which mark-to-market accounting treatment is applied, the changes in fair value are not deferred through other comprehensive income on the balance sheet. Rather they are immediately recorded in total revenue on the statement of operations. For those derivatives that are designated and 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 on the balance sheet and the ineffective portion of the changes in the fair value of the contracts is recorded in total revenue on the statement of operations, in either case as such changes occur. When the hedged production is sold, the realized gains and losses on the contracts are removed from other comprehensive income and recorded in revenue. While the contract is outstanding, the unrealized and ineffective gain or loss may increase or decrease until settlement of the contract depending on the fair value at the measurement dates.

During the first quarter of 2006, we determined that the cash flow hedge accounting treatment previously applied to our natural gas derivative contracts should be discontinued due to projected changes in the 2006 physical production volumes hedged and to give us more flexibility in how we market our physical production. Beginning in the first quarter of 2006, we applied mark-to-market accounting treatment to all outstanding derivative contracts, therefore the changes in fair value are not deferred through other comprehensive income, but rather recorded in revenue immediately as unrealized gains or losses. Going forward, we will continue to evaluate the terms of new contracts entered into to determine whether cash flow hedge accounting treatment or mark-to-market accounting treatment will be applied. In the past, we used mark-to-market accounting treatment for our crude oil derivative contracts and cash flow hedge accounting treatment for our natural gas derivative contracts. Therefore, unrealized gains and losses on the change in fair value of natural gas derivative contracts between periods may not be comparable.

Included within total revenue for the years ended December 31, 2006, 2005, and 2004 was approximately $9.7 million in net gains, $2.3 million in net losses and $2.5 million in net losses, respectively, from hedging and derivative activity as shown in the table below.

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Natural gas contract settlements (Mcf)	$ 4,699	$ (1,230)	$ (328)
Crude oil contract settlements (Bbl)	--	(1,757)	(881)
Hedge premium reclassification (Mcf)	--	--	(686)
Mark-to-market unrealized change in fair value of gas derivative contracts (Mcf)	4,686	--	--
Mark-to-market reversal of prior period unrealized change in fair value of oil derivative contracts (Bbl)	(155)	565	--
Mark-to-market unrealized change in fair value of oil derivative contracts (Bbl)	500	155	(565)
Gain (loss) on hedging and derivatives	$ 9,730	$ (2,267)	$ (2,460)

The table below summarizes our outstanding derivative contracts reflected on the balance sheet at December 31, 2006 and 2005.

Transaction Date	Transaction Type	Beginning	Ending	Price Per Unit	Volumes Per Day	Fair Value of Outstanding Hedging and Derivative Contracts as of December 31, 2006	2005
						(in thousands)	
Natural Gas (1):							
08/05	Natural Gas Collar	01/01/2006	12/31/2006	$7.00-$10.50	10,000MMbtu	$ –	$ (2,498)
08/05	Natural Gas Collar	01/01/2006	12/31/2006	$7.00-$16.10	10,000MMbtu	--	(137)
08/06	Natural Gas Collar (3)	01/01/2007	12/31/2007	$7.50-$11.50	5,000 MMbtu	2,301	--
08/06	Natural Gas Collar (3)	01/01/2007	12/31/2007	$7.50-$12.00	5,000 MMbtu	2,385	--
Crude Oil (2):							
08/05	Crude Oil Collar	01/01/2006	12/31/2006	$55.00-$80.00	400Bbl	--	156
08/06	Crude Oil Collar	01/01/2007	12/31/2007	$70.00-$87.50	400 Bbl	1,047	--
12/06	Crude Oil Swap	01/01/2007	12/31/2007	$66.00	600 Bbl	212	--
12/06	Crude Oil Swap	01/01/2008	12/31/2008	$66.00	1,500 Bbl	(758)	--
						$ 5,187	$ (2,479)

(1) Our current natural gas derivative contracts were entered into on a per MMbtu delivered price basis, using the Houston Ship Channel Index. Cash flow hedge accounting, which was applied to these contracts in 2005, was discontinued in 2006. During 2006, mark-to-market accounting treatment was applied to these contracts and the change in fair value is reflected in total revenue during the year.

(2) Cash flow hedge accounting is not applied to our crude oil contracts, which were entered into on a per barrel delivered price basis, using the West Texas Intermediate Light Sweet Crude Oil Index. Mark-to-market accounting treatment is applied to these contracts and the change in fair value is reflected in total revenue during the year.

(3) Subsequent to December 31, 2006, two natural gas collars covering a portion of our 2007 estimated production were terminated and replaced with new collars. The terms of the new contracts are detailed below.

Derivative contracts entered into after December 31, 2006 were as follows:

Transaction Date	Transaction Type (1)		Effective Dates Beginning	Effective Dates Ending	Price Per Unit	Volume Per Day
01/07	Natural Gas Collar		01/01/08	12/31/08	$7.50-$9.00	10,000 MMbtu
01/07	Natural Gas Collar		01/01/08	12/31/08	$7.50-$9.02	10,000 MMBtu
01/07	Natural Gas Collar	(2)	02/01/07	12/31/07	$7.02-$9.00	15,000 MMBtu
01/07	Natural Gas Collar	(2)	02/01/07	12/31/07	$7.00-$9.00	15,000 MMBtu
01/07	Natural Gas Collar		02/01/07	12/31/07	$7.00-$9.00	10,000 MMbtu
01/07	Natural Gas Collar		01/01/08	12/31/08	$7.50-$9.00	20,000 MMBtu

(1) Our January 2007 natural gas collars were entered into on a per MMbtu delivered price basis, using the NYMEX Natural Gas Index. Mark-to-market accounting treatment will be applied to these contracts and the change in fair value will be reflected in total revenue.

(2) These natural gas collars replaced contracts that were cancelled subsequent to December 31, 2006.

Sales to Major Customers

We sold natural gas and crude oil production representing 10% or more of our total revenues to the following major customers for the years ended December 31, 2006, 2005, and 2004.

Purchaser	For the Year Ended December 31, 2006	2005	2004
Kinder Morgan	37%	29%	*
Chevron Corporation	12%	18%	22%
Copano Field Services	10%	17%	19%
Kerr-McGee Oil & Gas	10%	*	*
Upstream Energy Services (1)	3%	5%	22%

* Zero or less than 1%.

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

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

In the exploration, development and production business, production is normally sold to relatively few customers. Substantially all our customers are concentrated in the oil and gas industry, and our 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 compete with 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 *ITEM 1A. "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% of the leasehold. In addition, state conservation laws which 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 as 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. Under the provisions of the Energy Policy Act of 2005 (the "2005 Act"), the NGA has been amended to prohibit any forms of market manipulation in connection with the purchase or sale of natural gas, and the FERC has issued new regulations to implement this prohibition. In addition, under the 2005 Act the FERC has been directed to establish new regulations that are intended to increase natural gas pricing transparency through, among other things, expanded dissemination of information about the availability and prices of gas sold. The 2005 Act also has significantly increased the penalties for violations of the NGA.

Our natural gas sales are affected by intrastate and interstate gas transportation regulation. Following the Congressional passage of the Natural Gas Policy Act of 1978 ("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, we cannot predict whether or to what extent that trend will continue, or what the ultimate effect will be on our sales of gas. 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. These gathering facilities are regulated for safety compliance by the U.S. Department of Transportation ("DOT") and/or by state regulatory agencies. In 2004, the DOT implemented regulations requiring that pipeline operators implement a pipeline integrity management program that must at a minimum include an inspection of certain pipeline facilities within ten years, and at least every seven years thereafter. In addition, beginning in early 2006, the DOT's Pipeline and Hazardous Materials Safety Administration commenced a rulemaking proceeding to develop rules that would better distinguish onshore gathering lines from production facilities and transmission lines, and to develop safety requirements better tailored to gathering line risks. We are not able to predict with certainty the final outcome of this rulemaking proposal.

The intrastate pipeline system in Texas is regulated for safety compliance by the DOT and the Texas Railroad Commission. In 2002, the United States Congress enacted the Pipeline Safety Improvement Act of 2002, which contains a number of provisions intended to increase pipeline operating safety. The DOT's final regulations implementing the 2002 act became effective in February 2004. Among other provisions, the regulations require that pipeline operators implement a pipeline integrity management program that must at a minimum include an inspection of gas transmission pipeline and nonrural gathering facilities within the next ten years, and at least every seven years thereafter. In December 2006, Congress enacted the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, which reauthorizes the programs adopted under the 2002 Act, proposes enhancements for state programs to reduce excavation damage to pipelines, establishes increased federal enforcement of one-call excavation programs, and establishes a new program for review of pipeline security plans and critical facility inspections. In addition, beginning in October 2005, the DOT's Pipeline and Hazardous Materials Safety Administration commenced a rulemaking proceeding to develop rules that would better distinguish onshore gathering lines from production facilities and transmission lines, and to develop safety requirements better tailored to gathering line risks. On March 15, 2006, the DOT revised its regulations to define more clearly the categories of gathering facilities subject to DOT regulation, establish new safety rules for certain gathering lines in rural areas, revise the current regulations applicable to safety and inspection of gathering lines in nonrural areas, and adopt new compliance deadlines. We are not able to predict with certainty the final impact of these new rules on the pipelines that we will acquire in the Smith acquisition. In addition to safety regulation, state regulation of gathering facilities generally includes various environmental, and in some circumstances, nondiscriminatory take requirements, but does not generally entail rate regulation. Natural gas gathering may receive greater regulatory rate and service scrutiny at the state level 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. 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. 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. In March 2006, to implement the second of the required five-yearly re-determinations, the FERC established an upward adjustment in the index to track oil pipeline cost changes. The FERC determined that the Producer Price Index for Finished Goods plus 1.3 percent (PPI plus 1.3 percent) should be the oil pricing index for the five-year period beginning July 1, 2006. We are not able at this time to predict the effects of these regulations or FERC proceedings, 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.

The U.S. Congress and various states are currently considering proposed legislation directed at reducing "greenhouse gas emissions." It is not possible at this time to predict how legislation that may be enacted to address greenhouse gas emissions would impact the oil and gas exploration and production business. However, future federal laws and regulations, if enacted, could result in increased compliance costs or additional operating restrictions and adversely affect our business and prospects.

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. 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.

ITEM 1A. 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* – GENERAL OVERVIEW - 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* – RISK MANAGEMENT ACTIVITIES - DERIVATIVES AND HEDGING" and *ITEMS 1 AND 2. "BUSINESS AND PROPERTIES* — OIL AND NATURAL GAS RESERVES" and "– MARKETING."

We have in the past (most recently in the third quarter of 2006) 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, but 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* – RISK MANAGEMENT ACTIVITIES - DERIVATIVES AND HEDGING" 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 *ITEM 4. "SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS* – EXECUTIVE OFFICERS OF THE REGISTRANT" and "-SIGNIFICANT EMPLOYEES."

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."

High demand for field services and equipment and the ability of suppliers to meet that demand may limit our ability to drill and produce our oil and natural gas properties.

Due to current industry demands, well service providers and related equipment and personnel are in short supply. This is causing escalating prices, delays in drilling and other exploration activities, the possibility of poor services coupled with potential damage to downhole reservoirs and personnel injuries. Such pressures will likely increase the actual cost of services, extend the time to secure such services and add costs for damages due to any accidents sustained from the over use of equipment and inexperienced personnel.

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 2007 both through increased drilling efforts and possible acquisitions. Any future growth may place a significant strain on our financial, technical, operational and administrative resources. In particular, the Smith acquisition, which was completed in January 2007, has resulted in a significant growth in our assets, reserves and revenues and may place a significant strain on our financial, technical, operational and administrative resources. We may not be able to integrate the operations of the acquired assets without increases in costs, losses in revenues or other difficulties. In addition, we may not be able to realize the operating efficiencies, synergies, costs savings or other benefits expected from the Smith acquisition. Any unexpected costs or delays incurred in connection with the integration could have an adverse effect on our business, results of operations or financial condition. We currently do not expect to hire any personnel associated with Smith. We have added to our staffing levels as a result of the Smith acquisition, and we intend to hire approximately 5 additional employees that we expect will be required to manage the increased scale of our business. However, we may experience difficulties in finding the additional qualified personnel. In an effort to stay on schedule with our planned activities in 2007, we intend to supplement our staff with contract and consultant personnel until we are able to hire new employees.

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 ours. We may not be able to conduct our operations successfully, 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. Such competitors may also be in a better position to secure oilfield services and equipment on a timely basis or on favorable terms. 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 SFAS 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 on our common stock and the incurrence of liens. The 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 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 cost 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. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations. We may be left with no recourse for liabilities and other problems associated with acquisitions that we do not discover prior to the closing date. 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.

Approximately 36% of the proved reserves associated with the Smith acquisition in January 2007 and approximately 23% of our proved reserves were undeveloped as of December 31, 2006, and those reserves may not ultimately be developed.

As of December 31, 2006, approximately 36% of the proved reserves associated with the Smith acquisition in January 2007 and approximately 23% of our proved reserves were undeveloped. Proved undeveloped reserves, by their nature, are less certain than other categories of proved reserves. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations and involves greater risks. Our reserve data for the properties assumes that to develop our reserves we will make significant capital expenditures and conduct these operations successfully. Although we have prepared estimates of these natural gas and oil reserves and the costs associated with these reserves in accordance with industry standards and SEC requirements, the estimated costs may not be accurate, development may not occur as scheduled and actual results may not be as estimated.

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

We have not historically paid a dividend on our common stock, cash or otherwise, and do not intend to in the foreseeable future. We are currently restricted from paying dividends on common stock by our existing credit facility agreement and, in some circumstances, by the terms of our Series A preferred stock. Any future dividends also may be restricted by our then-existing debt agreements. See *ITEM 7. "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS* – LIQUIDITY AND CAPITAL RESOURCES" and Notes 10 and 12 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, third-party facilities and 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 stockholders with 15% or more of outstanding voting stock.

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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

CERTAIN DEFINITIONS

The definitions set forth below shall apply to the indicated terms as used in this Annual Report. 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.

MMcf/d. One million cubic feet per day.

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.

MMcfe/d. One million cubic feet equivalent per day.

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.

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 our 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 material adverse effect on our financial condition, results of operations or cash flows, except as set forth below.

Texas Comptroller Audit - During the second quarter of 2004, we received notice that a subsidiary's franchise tax returns for the State of Texas would be audited for the tax years 1999 through 2002. After reviewing the 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 us to our subsidiary, which were 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 2006, we and the Comptroller agreed upon a method of computing our franchise tax liability to the State of Texas for the tax years 1999 through 2002 that resulted in a total one-time payment of $144,474, plus penalties of $9,228 which was recorded in 2006. Interest on this settlement of $40,150 was paid in the fourth quarter of 2006.

Wade and Joyce Montet, et al., v. Edge Petroleum Corp of Texas, et al., consolidated with Rolland L. Broussard, et al., v. Edge Petroleum Corp of Texas, et al. - This is a consolidated suit, filed in state court in Vermilion Parish, Louisiana in September 2003. Plaintiffs are mineral/royalty owners under the Norcen-Broussard No. 1 and 2 wells, Marg Tex Reservoir C, Sand Unit A (Edge's old Bayou Vermilion Prospect). They claim the operator at the time, Norcen Explorer, now Anadarko, failed to "block squeeze" the sections of the No. 2 well, as a prudent operator, according to their allegations, would have done, to protect the gas reservoir from being flooded with water from adjacent underground formations. Plaintiffs further allege Norcen was negligent in not creating a field-wide unit to protect their interests. The allegations relate to actions taken beginning in the early 1990's. Plaintiffs have named us and other working interest owners in the leases as defendants, including Norcen Explorer's successors in interest, Anadarko. Plaintiffs originally sought unspecified damages for lost royalties and damages due to alleged devaluation of their mineral and property interests, plus interest and attorneys' fees. In early 2005, we filed a motion for summary judgment in the case asserting, among other defenses, that: (i) there has been no breach of contract, (ii) there is no express or implied duty imposed on us to block squeeze the well or form a field-wide unit, (iii) the units were properly formed by the Conservation Commissioner in accordance with the statutory scheme in Louisiana, (iv) plaintiffs' claims are barred by limitations, and (v) other defenses. Along with the other defendants, we also filed a special peremptory challenge of no cause of action under the leases and the Louisiana Mineral Code for failure to exhaust administrative remedies and due to lack of a demand. In May and June 2005, the court ruled against us on the motion for summary judgment and the peremptory challenges. Of the 18.75% after-payout working interest that was originally reserved in the leases, we owned a 2.8% working interest at the time of the alleged acts or omissions. On September 6, 2005, we filed a third-party demand to join the other working interest owners who hold the remainder of the 18.75% working interest as third-party defendants in this case. These third-parties consist, for the most part, of partnerships that are directly or indirectly controlled by John Sfondrini, a director of ours, and hold an aggregate 14.7% working interest (the "Sfondrini Partnerships"). Vincent Andrews, also a director of ours, owns a minority interest in the corporate general partner of one of the partnerships. The Sfondrini Partnerships consist of (1) Edge Group Partnership, a general partnership composed of limited partnerships of which Mr. Sfondrini and a company controlled by Mr. Sfondrini are general partners; (2) (A) Edge Option I Limited Partnership, (B) Edge Option II Limited Partnership and (C) Edge Option III Limited Partnership, limited partnerships of which Mr. Sfondrini and a company controlled by Mr. Sfondrini are general partners; and (3) BV Partners Limited Partnership, a limited partnership of which a company controlled by Messrs. Sfondrini and Andrews is general partner and of which Mr. Sfondrini is manager (and of which company Mr. Andrews is an officer). These partnerships were among the third party defendants that we have sought to join in the case, and these partnerships have for the most part filed answers denying any liability to us. We participated for our 2.8% share of the well costs and revenues for the Broussard No. 2 well, as did the other defendants for their share, including the third-party defendant partnerships who participated for 14.7%. We strongly believe the parties should only be liable for their proportionate share of any damages award should a finding of liability occur in the case. We intend to vigorously contest the plaintiffs' claims.

As of the date of this report, it is not possible to determine what, if any, our ultimate exposure might be in this matter. Prior to the settlement described below, plaintiffs had asserted damages, including interest, to be as high as

$63 million. The plaintiffs' expert witness, in his December 2005 deposition, offered his theory that plaintiffs' gross damages are in the range of $19 to $22 million. That number is based on his theory that the alleged failure to block squeeze the well resulted in the under-production of gas worth $300 million. Plaintiffs' royalty share of that figure yields the $19 to $22 million range of alleged damages. Based on the expert's testimony, damages attributable to the full 18.75% interest would be in the range of $3.75 million gross or net to our 2.8% share would be in the range of $560,000 (excluding interest and attorneys' fees). Along with the other defendants, we hired our own expert witnesses who have refuted these claims, particularly the expert's assertions that failure to block squeeze the well caused any damages to the reservoir. The deposition of a Norcen engineer who prepared the completion plan for the Broussard No. 2 well and supervised the completion operations, taken in April 2006, confirms the testimony of the defense experts as to why the well was not block squeezed. The plaintiffs have also retained a damages expert who has given a report that the damages in this case are in the range of $30 million, excluding interest and attorneys' fees. Our share of that amount based on the full 18.75% would be approximately $5.6 million and net to our 2.8% share would be approximately $840,000. We participated in mediation of this lawsuit on July 18, 2006, but the parties failed to reach an agreement. In July 2006, the plaintiffs' attorney sent a demand to the defendants for total damages claimed by plaintiffs, with legal interest, totaling $63 million. Our share of that amount based on the full 18.75% interest would be approximately $12.2 million and net to our 2.8% interest would be approximately $1.8 million. On July 31, 2006 the Judge granted the defendant groups' motion for partial summary judgment dismissing plaintiffs' tort-based claims. Also on the same date, the Judge granted the defendant groups' motion for partial summary judgment seeking to deny the plaintiffs an award of attorneys' fees and also to dismiss any claim of plaintiffs that defendants had an obligation to form a field-wide unit.

Broussard Plaintiff Settlement.

On December 19, 2006, we, along with the other defendants in this suit, reached a settlement agreement with the Broussard Plaintiffs in full settlement of their 72% of the total claims made in this consolidated action. This settlement was finalized in January 2007. Our share of this settlement totaled approximately $208,000, which was recorded in December 2006, and the Sfondrini Partnerships' share totaled $1,109,759. The settlement with the Broussard Plaintiffs was finalized on February 1, 2007, and the defendants and the third-party defendants including the Sfondrini Partnerships were released from all claims by the Broussard Plaintiffs.

The Sfondrini Partnerships did not have sufficient cash to fund their respective full portion of the settlement. Therefore, in order to facilitate the settlement, we purchased certain oil and gas properties from certain of the Sfondrini Partnerships, with the proceeds of such sale and purchase generally being directed to payment of the Broussard settlement, in full satisfaction of the Sfondrini Partnerships' share of such settlement. The oil and gas properties that we purchased from the Sfondrini Partnerships and their respective purchase prices are as follows:

(1) 100% of each of Edge Group Partnership's, Edge Option I Limited Partnership's, Edge Option II Limited Partnership's and Edge Option III Limited Partnership's interest in the Ilse Miller No. 2 Well and leases, Wharton County, Texas, for a total combined value of $51,243.

(2) 100% of each of Edge Group Partnership's, Edge Option I Limited Partnership's, Edge Option II Limited Partnership's and Edge Option III Limited Partnership's interest in the Wm Baas 2-16 No. 1 Well and leases, Monroe County, Alabama, for a total combined value of $14,407.

(3) 55.953% of Edge Group Partnership's interest in certain wells and leases in the Company's Austin and Nita prospects, for a total value of $1,044,109.

In the purchase and sale transaction between us and the Sfondrini Partnerships, BV Partners Limited Partnership, whose 2.48% share of the Broussard settlement amount was $186,000 (as determined by us and Mr. Sfondrini on behalf of the BV Partners Limited Partnership), did not sell any assets to us and did not have sufficient funds to satisfy their share of the settlement amount. In addition, the Edge Option I, II and III Limited Partnerships did not have sufficient assets to satisfy their respective .34%, .34% and 2.25% shares of the settlement amount, which we and Mr. Sfondrini determined to be $25,750, $25,750 and $169,102, respectively. The shortfall amounts of Edge Option I, II and III Limited Partnerships were, net of assets that they sold to us, determined by us and Mr. Sfondrini to be $24,333, $24,333 and $163,276, respectively. As a result, Edge Group Partnership sold additional properties (over the amount necessary to fund its portion of the settlement) to us at fair market value in an amount sufficient to allow it to have proceeds from such sale to fund BV Partners Limited Partnership's share of the settlement and the remaining shortfall amounts owed by Edge Option I, II and III. In return, BV Partners and Edge Option I, II and III contributed all of their interest in the Bayou Vermilion Prospect leases and the Trahan No. 3 well located thereon to Edge Group Partnership. The fair market value of these interests contributed to Edge Group by BV Partners Limited Partnership and Edge Option I, II and III were determined by us and Mr. Sfondrini on behalf of such partnerships to be $27,793, $3,847, $3,847 and $25,263, respectively.

The valuations of the interests of the Sfondrini Partnerships purchased by us and the interests contributed to Edge Group Partnership by BV Partners and Edge Option I, II and III were made at an agreed value, using a PV10 model and assuming $7.50/MMBtu gas and $60/BBl oil, which we believed represented current pricing levels for oil and gas properties at the time, and were agreed to by us and Mr. Sfondrini, on behalf of the Sfondrini Partnerships.

The trial on the remaining claims, those of the Montet plaintiffs (approximately 28% of the original aggregate claims in the case), is now set for trial beginning August 27, 2007. The Montet plaintiffs' calculation of their alleged damages has not changed. If the jury were to adopt the plaintiffs' damage figures, the total damages attributable to the Montet plaintiffs could be approximately $17.6 million. The defendants' exposure for an 18.75% share of that number would be approximately $3.31 million. The exposure for our approximate 2.8% share would be approximately $493,000. If there were a damage award against the defendants, we believe that ultimately we should only be liable for our 2.8% share of any such award unless a co-party defendant, including any of the third-party defendants, cannot satisfy their share of any final judgment or settlement amount or are found not to be liable to us on our third-party demand. In that event, we could be held responsible for more than our 2.8% share. We believe we have meritorious defenses and intend to continue to vigorously contest this suit and our third-party demands against the partnerships. We have not established a reserve with respect to these claims.

We may have insurance coverage for all or part of this claim up to the policy limits of $1 million per occurrence and $2 million in the aggregate. A claim was submitted to Mid-Continent Casualty Company, our casualty carrier, who is currently providing a defense under a reservation of rights letter. However, on July 3, 2006, Mid-Continent filed a suit for declaratory judgment against us in federal district court in Houston, Texas seeking to determine whether it has a duty to indemnify us and certain other defendants for this loss under the policies at issue. Mid-Continent has asked the court to declare they have no obligation to indemnify us and the third-party defendants based on certain technical definitions under the policies and the fact that the plaintiffs' claims are based on alleged breaches of contract. We are both vigorously defending the declaratory judgment action, and actively seeking indemnity under the policies at issue for our potential liabilities, if any, to the plaintiffs in the Louisiana actions. We are also pursuing coverage claims under other insurance policies that could cover a portion of our share of a loss in this case.

David Blake, et al. v. Edge Petroleum Corporation – On September 19, 2005, David Blake and David Blake, Trustee of the David and Nita Blake 1992 Children's Trust filed suit against us in state district court in Goliad County, Texas alleging breach of contract for failure and refusal to transfer overriding royalty interests to plaintiffs in at least five leases in Goliad County, Texas and failure and refusal to pay monies to Blake pursuant to such overriding royalty interests for wells completed on the leases. The plaintiffs seek relief of (1) specific performance of the alleged agreement, including granting of overriding royalty interests by us to Blake; (2) monetary damages for failure to grant the overriding royalty interests; (3) exemplary damages for his claims of business disparagement and slander; (4) monetary damages for tortuous interference; and (5) attorneys' fees and court costs. Venue of the case was transferred to Harris County, Texas by agreement of the litigants. We have served plaintiffs with discovery and have filed a counterclaim and an amended counterclaim joining various related entities that are controlled by plaintiffs. In addition, plaintiffs have filed an amended complaint alleging claims of slander of title and tortuous interference related to its alleged right to receive an overriding royalty interest from a third party. Plaintiffs currently have on file an amended motion for summary judgment, to which we have filed a response. In addition, we have filed a motion for summary judgment on the plaintiffs' case. In December 2006, the court denied our motion for summary judgment. The court has not ruled on Blake's motion. The trial setting in March 2007 has been postponed by agreement of the parties and reset to September 15, 2007. Discovery in the case has commenced and is continuing. We have responded aggressively to this lawsuit, and believe we have meritorious defenses and counterclaims.

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 66 years old.

Michael G. Long has served as Executive Vice President and Chief Financial Officer of the Company since April 2005 and as Senior Vice President and Chief Financial Officer 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 54 years old.

John O. Tugwell has served as Chief Operating Officer and Executive Vice President since April 2005 and prior to that served as Chief Operating Officer and Senior Vice President of Production for the Company since March 2004 and prior to that as Vice President of Production since March 1997. He served as Senior Petroleum Engineer of the Company's predecessor corporation since May 1995. From 1986 to May 1995, Mr. Tugwell 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 43 years old.

Significant Employees

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 56 years old.

Howard Creasey has served as the Senior Vice President of Exploration since October 2006 and prior to that as the Vice President of Exploration since October 2005. Before October 2005, Mr. Creasey was Chief Geologist for the Company since October 2003. From April of 1999 until October 2003 he served as a Senior Staff Geologist for Devon Energy and its predecessor Ocean Energy. Prior to April 1999 for 14 years Mr. Creasey served as President and Exploration Geologist for Moss Rose Energy, Inc., a company he started in 1986. Mr. Creasey holds a B.S. in Geology from Stephen F. Austin State University, has been a member of the AAPG for over 25 years and is a Certified Geoscientist in the State of Texas. Mr. Creasey is 51 years old.

Kirsten A. Hink has served as Vice President and 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 40 years old.

Kurt P. Primeaux has served as Vice President of Production since October 2006, Manager of Production Operations from April 2004 to October 2006, and before that, as Senior Petroleum Engineer from August 2003 to April 2004. Prior to joining the Company, he held similar positions with Union Oil of California from June 1998 to August 2003, most recently that of Resource Manager. Mr. Primeaux began his career with Texaco USA in 1988 and has over 18 years experience in reservoir, drilling, production and operations engineering. He holds a B.S. degree in Petroleum Engineering from Louisiana State University and an M.S. degree in Environmental Engineering from Tulane University. He is 43 years old.

R. Keith Turner has served as Vice President of Land for the Company since September 2006. Before moving to the Land Department, Mr. Turner was a Staff Attorney in the Legal Department since 2003. Prior to joining the Company in 2003, Mr. Turner served in various capacities with Newfield Exploration Company, Fina Oil and Chemical Company and Torch Energy Advisors, Inc. He received a B.S. in Science from Stephen F. Austin State University and a J.D. degree from South Texas College of Law. Mr. Turner is 52 years old.

Robert C. Thomas has served as Senior Vice President, General Counsel and Corporate Secretary since October 2006 and prior to that 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 53 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 8, 2007, we estimate there were approximately 236 record holders of our common stock. Our common stock is listed on the NASDAQ Global Select Market ("NASDAQ") and traded under the symbol "EPEX". As of March 8, 2007, we had 28,383,455 shares outstanding and our closing price on NASDAQ was $11.97 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 2006		
First Quarter	34.65	22.89
Second Quarter	26.85	16.60
Third Quarter	21.58	15.28
Fourth Quarter	20.26	15.00
Calendar 2005		
First Quarter	18.24	13.40
Second Quarter	16.86	12.46
Third Quarter	27.94	15.47
Fourth Quarter	28.49	20.05

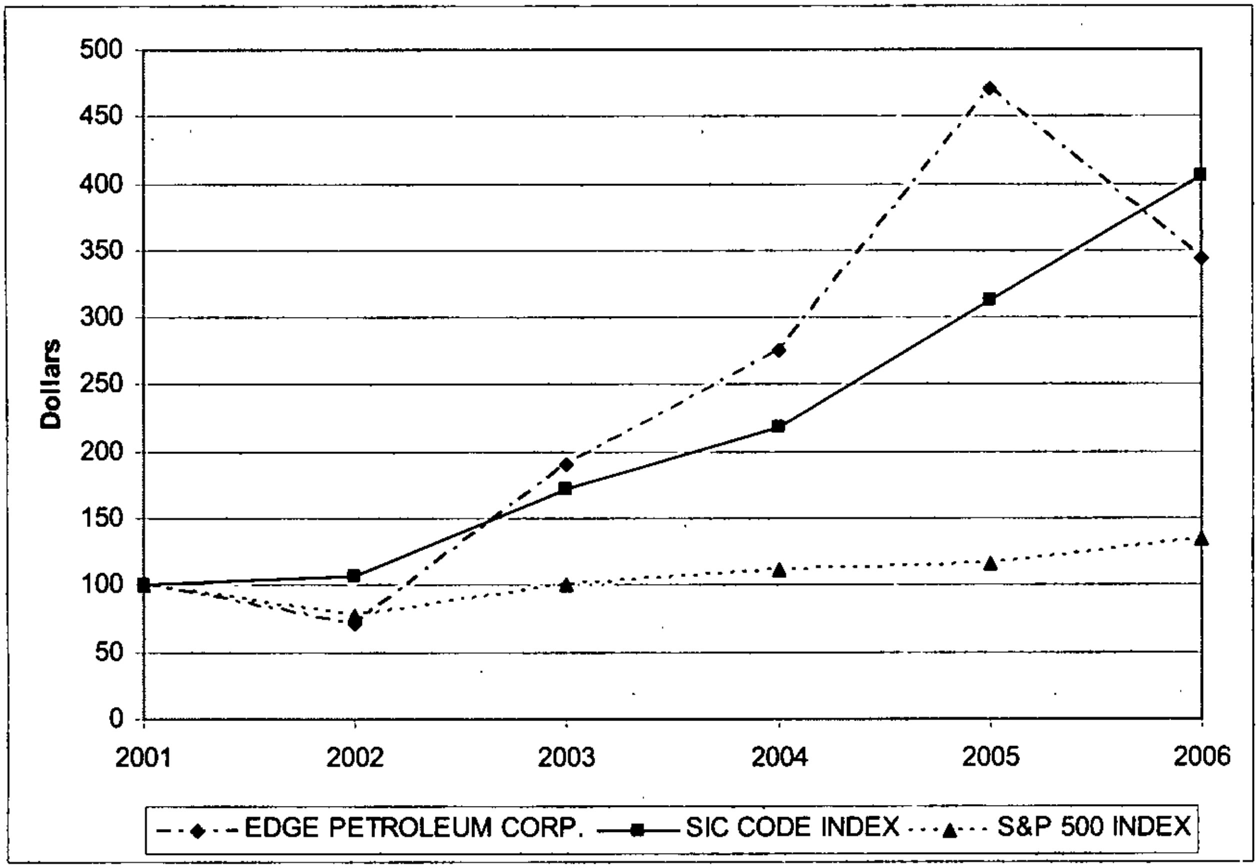
We have never paid a dividend on our common stock, cash or otherwise, and do not intend to in the foreseeable future. In addition, under our current credit facility, we are restricted from paying cash dividends on our common stock. The payment of future dividends, if any, will be determined by our Board 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 1A. "RISK FACTORS* – We do not intend to pay dividends on our common stock and our ability to pay dividends on our common stock is restricted."

There were no repurchases of securities during the fourth quarter of 2006.

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 ("S&P 500 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, 2001 and ending December 31, 2006.

COMPARE 5-YEAR CUMULATIVE TOTAL RETURN
AMONG EDGE PETROLEUM CORPORATION, S&P 500 INDEX
AND SIC CODE 1311 INDEX



The graph assumes that $100 was invested on December 31, 2001 in each of Edge common stock, the S&P 500 Index and the SIC Code 1311 companies and assumes that all dividends were reinvested:

	Edge Petroleum	S&P 500 Index	SIC Code Index
December 31, 2001	$100.00	$100.00	$100.00
December 31, 2002	$70.75	$77.90	$106.61
December 31, 2003	$190.94	$100.25	$171.22
December 31, 2004	$275.09	$111.15	$217.51
December 31, 2005	$470.00	$116.61	$312.49
December 31, 2006	$344.15	$135.03	$406.32

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 *ITEM 8. "FINANCIALS STATEMENTS AND SUPPLEMENTARY DATA"*:

	Year Ended December 31,				
	2006 (1) (2)	2005 (3)	2004 (4)	2003 (5)	2002
	(in thousands, except per share amounts)				
Statement of operations:					
Oil and natural gas revenue	$ **129,744**	$ 121,183	$ 64,505	$ 33,926	$ 20,911
Operating expenses:					
Oil and natural gas operating expenses including production and ad valorem taxes	**18,257**	17,068	9,309	5,116	3,831
Depletion, depreciation, amortization and accretion (5)	**61,080**	40,218	21,928	13,577	10,427
Impairment of oil and natural gas properties (6)	**96,942**	--	--	--	--
General and administrative expenses and bad debt expense	**13,788**	12,436	9,447	7,132	5,229
Total operating expenses	**190,067**	69,722	40,684	25,825	19,487
Operating income (loss)	**(60,323)**	51,461	23,821	8,101	1,424
Interest expense and amortization of deferred loan costs, net of amounts capitalized	**(2,665)**	(153)	(473)	(679)	(228)
Interest income	**152**	128	36	17	27
Income (loss) before income taxes and cumulative effect of accounting change	**(62,836)**	51,436	23,384	7,439	1,223
Income tax (expense) benefit	**21,575**	(18,078)	(8,255)	(2,731)	(473)
Income (loss) before cumulative effect of accounting change	**(41,261)**	33,358	15,129	4,708	750
Cumulative effect of accounting change (5)	**--**	--	--	(358)	--
Net income (loss)	$ **(41,261)**	$ 33,358	$ 15,129	$ 4,350	$ 750
Basic earnings (loss) per share:					
Income (loss) before cumulative effect of accounting change	$ **(2.38)**	$ 1.95	$ 1.16	$ 0.48	$ 0.08
Cumulative effect of accounting change	**--**	--	--	(0.03)	--
Basic earnings (loss) per share	$ **(2.38)**	$ 1.95	$ 1.16	$ 0.45	$ 0.08
Diluted earnings (loss) per share :					
Income (loss) before cumulative effect of accounting change	$ **(2.38)**	$ 1.87	$ 1.11	$ 0.47	$ 0.08
Cumulative effect of accounting change (5)	**--**	--	--	(0.03)	--
Diluted earnings (loss) per share	$ **(2.38)**	$ 1.87	$ 1.11	$ 0.44	$ 0.08
Basic weighted average number of shares outstanding (7)	**17,368**	17,122	13,029	9,726	9,384
Diluted weighted average number of shares outstanding (7)	**17,368**	17,815	13,648	9,988	9,606
EBITDA Reconciliation (8):					
Net income (loss)	$ **(41,261)**	$ 33,358	$ 15,129	$ 4,350	$ 750
Cumulative effect of accounting change (5)	**--**	--	--	358	--
Income tax expense (benefit)	**(21,575)**	18,078	8,255	2,731	473
Interest expense and amortization of deferred loan costs, net of amounts capitalized	**2,665**	153	473	679	228
Interest income	**(152)**	(128)	(36)	(17)	(27)
Depletion, depreciation, amortization and accretion (5)	**61,080**	40,218	21,928	13,577	10,427
EBITDA	$ **757**	$ 91,679	$ 45,749	$ 21,678	$ 11,851

	As of December 31,				
	2006 (1) (2)	2005 (3)	2004 (4)	2003 (5)	2002
			(in thousands)		
Selected Cash Flow Data:					
Net cash provided by operating activities	$ **97,409**	$ 93,111	$ 42,270	$ 23,898	$ 10,408
Net cash used in investing activities	$ **(140,412)**	$ (167,280)	$ (89,410)	$ (28,070)	$ (19,255)
Net cash provided by financing activities	$ **44,418**	$ 72,568	$ 48,080	$ 2,931	$ 10,623
Selected Balance Sheet Data:					
Working capital (9)	$ **10,162**	$ 10,537	$ 8,957	$ 948	$ 3,310
Property and equipment, net	**289,457**	306,456	165,840	97,981	75,682
Total assets	**321,657**	343,380	190,990	118,012	85,576
Long-term debt, including current maturities	**129,000**	85,000	20,000	21,000	20,500
Stockholders' equity (7)	**156,052**	191,755	150,467	82,011	58,533

(1) As discussed in Note 6 to our consolidated financial statements, we completed one significant property acquisition in December 2006 and various other working interest acquisitions throughout the year, which could affect the comparability of our results in 2006 to prior periods.

(2) As discussed in Note 9 to our consolidated financial statements, in 2006 we discontinued the use of cash flow hedge accounting on our natural gas contracts. During 2006, mark-to-market accounting treatment was applied to these contracts, which affects the comparability of our results in 2006 to prior periods.

(3) As discussed in Note 6 to our consolidated financial statements, we completed one property acquisition and one corporate acquisition in the fourth quarter of 2005, which affects the comparability of our results in 2005, and subsequent periods, to prior periods.

(4) As discussed in Note 6 to our consolidated financial statements, we completed the merger with Miller in December 2003, which affects the comparability of our results in 2004, and subsequent periods, to prior periods.

(5) As discussed in Note 7 to our consolidated financial statements, effective January 1, 2003, we changed our method of accounting for asset retirement obligations, which affects the comparability of our results in 2003, and subsequent periods, to prior periods.

(6) As discussed in Note 2 to our consolidated financial statements, in the third quarter of 2006 we recorded an impairment of oil and natural gas properties in the amount of $96.9 million ($63.0 million, net of tax) as a result of our full-cost ceiling test. The impairment of oil and natural gas properties was primarily the result of a decline in natural gas prices at September 30, 2006, the date of impairment measurement for the full-cost ceiling test. No such impairment was necessary in the years 2002 through 2005.

(7) 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 and subsequent periods are not directly comparable to periods prior to 2004.

(8) 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 adjusted for the full-cost ceiling test impairment recorded in 2006. EBITDA is a financial measure commonly used in the oil and natural gas industry, but is not defined under accounting principles generally accepted in the United States of America ("GAAP"). EBITDA 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 provides additional information about our ability to meet our future liquidity requirements for debt service, capital expenditures and working capital. In addition, management believes that EBITDA is a useful comparative measure of operating performance and liquidity. For example, debt levels, credit ratings and, therefore, the impact of interest expense on earnings vary significantly between companies. Similarly, the tax positions of individual companies can vary because of their differing abilities to take advantage of tax benefits, with the result that their effective tax rates and tax expense can vary considerably. Finally, companies differ in the age and method of acquisition of productive assets, and thus the relative costs of those assets, as well as in the depreciation or depletion (straight-line, accelerated, units of production) method, which can result in considerable variability in depletion, depreciation and amortization expense between companies. Thus, for comparison purposes, management believes that EBITDA can be useful as an objective and comparable measure of operating profitability and the contribution of operations to liquidity because it excludes these elements.

(9) Working Capital is defined as current assets less current liabilities.

We do not pay cash dividends on our common stock and have not in the periods presented above; therefore, they are not presented in the selected financial data. We expect to pay dividends on our 5.75% Series A cumulative convertible perpetual preferred stock issued in our January 2007 offering.

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 of Financial Condition and Results of Operations ("MD&A").

GENERAL OVERVIEW

Edge Petroleum Corporation ("Edge", "we" or the "Company") is a Houston-based independent energy company that focuses its exploration, development, production, acquisition 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. We generate 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 production activities that allow us to continue generating revenue, income and cash flows. We have also spent considerable efforts on acquisitions, including both corporate and asset acquisitions, which have contributed to our growth in recent years.

This overview provides our perspective on the individual sections of MD&A. 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 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 price-risk management activities.
- **Tax Matters** – supplementary discussion of income tax matters.
- **Recently Issued Accounting Pronouncements** – a discussion of certain recently issued accounting pronouncements 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, which makes future price movements difficult to predict. While our revenues are a function of both production and prices, wide swings in commodity prices have most often had the greatest impact on our results of operations. We have little ability to predict those prices or to control them without losing some advantage of the upside potential. During 2006, natural gas prices steadily declined from their record highs at the end of 2005. Crude oil prices spiked to an all-time high in the summer of 2006, but subsequently declined to a price similar to the price at the end of 2005. Despite these changes in 2006, oil and gas prices remain at historically high levels.

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. The high commodity price environment in 2005 led to increased costs in our industry, and in 2006, we saw commodity prices decline while operating costs continued to increase. These factors, together with increased demand for rigs, equipment, supplies and services, have made it difficult at times for us to further our growth, and made timely execution of our planned activities difficult.

Our business, as with other extractive businesses, is a depleting one in which each gas equivalent produced must be replaced or our asset base and capacity to generate revenues in the future 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 operational and 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 have chosen to seek geologic and geographic diversification by operating in multiple basins in order to mitigate risk in our operations. We also attempt to make selected acquisitions of oil and gas properties to augment our growth and provide future drilling opportunities.

We periodically hedge our exposure to volatile oil and gas prices on a portion of our production to reduce price risk. In 2006, we had 53% and 42% of our natural gas and crude oil production, respectively, hedged. As of March 9, 2007, we have derivative contracts in place covering approximately 60% and 72% of our anticipated 2007 natural gas and crude oil production, respectively, including the effect of the Smith acquisition which closed in January 2007, but before any other acquisitions that may occur.

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. Our Board recently approved a 2007 capital budget of approximately $140 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, proceeds from offerings of common stock or other securities under our shelf registration statement or other sources.

For 2006, we reported a 5% increase in annual production volumes over the 2005 period. We also replaced 97% of our total 2006 production (see *ITEMS 1 AND 2. "BUSINESS AND PROPERTIES* – OIL AND NATURAL GAS RESERVE REPLACEMENT"). At December 31, 2006, our net proved reserves were 102.1 Bcfe, of which approximately 77% were developed. In addition, in January 2007, we acquired certain oil and gas properties from Smith Production Inc., as discussed below in *"ACQUISITIONS AND DIVESTITURES - Acquisitions."* Following the completion of our two recent public offerings that resulted in net proceeds of approximately $276.7 million, we believe we are in a strong financial position. We have unused borrowing capacity of $85.0 million as of March 9,

2007. Operationally and financially, we believe we are well positioned to continue the execution of our business strategy during 2007.

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 growth objectives and we expect acquisitions will continue to play a significant role in our future plans for growth. Acquisitions add meaningful incremental increases in reserves and production and may range in size from acquiring a working interest in non-operated producing property to an entire field or company. Unlike drilling capital, which is planned and budgeted, acquisition capital is neither budgeted nor allocated. Specific timing and size of acquisitions cannot be predicted. Although we consider a wide variety of acquisitions, a significant part of our growth strategy is expected to be focused toward producing property acquisitions, which we believe have exploitable potential. Because of our financial flexibility, we are positioned to take advantage of opportunities to acquire producing properties as they may arise. In today's high-price environment, where production is providing greater cash flow and earnings to most companies in our industry, identifying quality opportunities is difficult. We believe through hard work, technical ability and creative thinking, we will continue to grow through both acquisitions and drilling. Any such acquisition could involve the payment by us of a substantial amount of cash or the issuance of a substantial number of additional shares or other securities.

On January 31, 2007, we completed the purchase. of certain oil and natural gas properties located in 13 counties in south and southeast Texas and other assets from Smith Production Inc. We paid approximately $389.8 million for these assets. In total, the Smith assets include approximately 150 gross producing wells (74 net) and an ownership interest in approximately 17,000 gross (12,250 net) developed acres and 56,000 gross (16,000 net) undeveloped acres of leasehold, all as of December 31, 2006. In addition to the properties and related acreage, we acquired from Smith certain gathering facilities and ownership of approximately 13 miles of natural gas gathering pipelines and related infrastructure serving certain producing assets in southeast Texas. The pipeline system transports our natural gas as well as third-party natural gas. We also acquired 25% of Smith's option and leasehold rights in an approximate 95 square mile 3-D exploration area with approximately 30,000 gross acres of leases and options located in the Mission project area in Hidalgo County in south Texas, with a primary focus on the Vicksburg formation. We acquired a 12.5% working interest in an approximate 160 square mile 3-D exploration area with approximately 55,000 gross acres of leases and options located in the Yates Ranch/Hostetter project area in McMullen and Duval Counties in south Texas. The 160 mile 3-D area increases our exposure to the Middle and Deep Wilcox trend. Furthermore, this venture allows us to participate in a proposed additional 3-D shoot covering approximately 120 square miles near the Yates Ranch within the Wilcox trend. We also acquired 25% of Smith's option and leasehold rights in an approximate 105 square mile 3-D exploration area with approximately 60,000 gross acres of leases and options in Newton County in southeast Texas and Beauregard Parish in Louisiana with a focus on prospects in the Frio, Yegua and Wilcox formations at depths ranging between 4,000 and 10,000 feet. We financed the Smith acquisition through concurrent public offerings of 10.925 million shares of our common stock and 2.875 million shares of our Series A preferred stock, along with borrowings under a new revolving credit facility.

On December 28, 2006, we completed an acquisition of certain working interests in the Chapman Ranch Field in Nueces County, Texas from Kerr-McGee, a wholly-owned subsidiary of Anadarko Petroleum Corporation. In late 2005, we acquired non-operated working interests ranging from 44% to 50% in several producing wells in this field, as discussed below. In the Kerr-McGee acquisition, we acquired an additional 44% to 50% working interest in the same wells in the field and acquired two additional wells, bringing our working interests in those Chapman Ranch properties, including a total of nine producing wells, to 88% to 100%. The base purchase price of the acquisition was $26.0 million. The purchase price was preliminarily adjusted at closing to approximately $25 million (including a previously paid deposit of $2.6 million) as a result of adjustments to the purchase price for the results of operations between the December 1, 2006 effective date and the December 28, 2006 closing date, and other purchase price adjustments. There may be post-closing adjustments to the purchase price for results of operations between the effective date and closing date as further information becomes available. We financed the purchase price of the Kerr-McGee acquisition through $24.0 million in borrowings under our credit facility, the borrowing base of which was increased in connection with this transaction (see Note 10 to our consolidated financial statements).

On September 21, 2005, we acquired (i) the stock of a private company, Cinco Energy Corporation ("Cinco"), whose primary asset is ownership of working interests in oil and natural gas properties located on the Chapman Ranch Field in south Texas and (ii) additional working interests in the same field owned by two other private companies for an aggregate cash purchase price of approximately $74.9 million (of which $46.9 million was attributable to the stock purchase and $28.0 million was attributable to the working interest asset purchase). We allocated approximately $17.5 million of the total purchase price to the unproved property category. The properties acquired from these entities are located in Nueces County, Texas and consisted of six producing wells, one well undergoing completion operations, and one well shut in for evaluation, as well as an ownership interest in approximately 1,300 net acres of developed and undeveloped leasehold. We financed the acquisitions through borrowings under our then-existing credit facility, the borrowing base of which was increased in connection with the acquisitions and other activities after the last redetermination.

On October 13, 2005, we consummated the Chapman Ranch Field asset acquisition for a final purchase price of $28.0 million. On November 30, 2005, we consummated the Cinco stock purchase for a final purchase price of $46.9 million.

On December 29, 2004, we acquired oil and natural gas properties located in south Texas from Contango Oil & Gas Company ("Contango") for a final purchase price of $40.1 million. We financed the acquisition with proceeds from a public offering of our common stock under our shelf registration (see Note 11 to our consolidated financial statements). The properties acquired consisted 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 also identified a substantial number of additional drilling locations on undeveloped acreage for which we realized much of the exploitable potential in 2005 and 2006. We believe this area to be a continued target of exploitable potential for us in future years.

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 the first half of 2006, we sold our Buckeye properties in Live Oak County, Texas for $627,645. During 2005, we had no divestitures. During 2004, our net proceeds from asset divestitures of $60,000 were primarily derived from the sale of certain oil and gas properties and equipment in Texas, Mississippi and Louisiana.

OUTLOOK

- We successfully completed one significant acquisition during 2006, as well as a large, transforming acquisition in the first quarter of 2007, both of which added valuable reserves in our core areas in Texas. We also completed smaller working interest acquisitions in 2006. We expect to continue to spend considerable effort in 2007 on acquisitions, as we seek to further our growth.
- We expect to drill between 80 and 90 wells (37 and 42 net, respectively) in 2007 and we estimate capital spending for the year to be approximately $140 million. Our ability to materially increase the number of wells to be drilled is heavily dependent upon the timely access to oilfield services, particularly drilling rigs. The shortage of available rigs in 2006 delayed the drilling of several wells, slowing growth in our production for the year.
- Drilling activities in the Fayetteville Shale play were initiated during the second quarter of 2006 and we expect that activity to continue into 2007.
- In order to manage our realized growth in 2006 and our anticipated growth for the next several years, we increased our headcount from 62 employees as of December 31, 2005 to 68 employees as of December 31, 2006, resulting in increased G&A costs for 2006. We have added and expect to continue to add to our staff levels again in 2007 both as a result of recent growth and anticipated future growth.
- To help protect against the possibility of downward commodity price movements and lost revenue, we have several derivatives in place to hedge a portion of our expected natural gas and crude oil production streams for 2007 and 2008. While there was no cash impact from our oil derivatives contracts, our gas derivatives contracts contributed $4.7 million to our cash flows in 2006. We discontinued cash flow hedge accounting treatment on our natural gas collars, and thus all of our derivative transactions are now accounted for using mark-to-market accounting treatment (see Note 9 to our consolidated financial statements).
- We recorded a $96.9 million ($63.0 million, net of tax) non-cash impairment relating to our oil and natural gas properties during the third quarter of 2006 resulting from our full-cost ceiling test. Natural gas prices

fell below $5.00 per MMBtu at September 30, 2006, but subsequently rose above $6.00 per MMBtu after the third quarter end, which we believe would have allowed us to avoid the impairment if, as would have been allowed under applicable accounting guidelines, we had elected to use such subsequent prices in determining the calculation of our ceiling test at September 30, 2006. However, oil and natural gas prices are expected to continue to be volatile in the future. The benefit of the write-down is that it is expected to decrease future depletion expense and we believe that it will more appropriately state our capitalized costs.

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 INFORMATION."

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 and 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 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 test. The ceiling is the discounted present value of our estimated total proved reserves adjusted for taxes and the impact of qualifying 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. A ceiling test impairment could result in a significant loss for a reporting period; however, future depletion expense would be correspondingly reduced. During the year ended December 31, 2006, we recorded a ceiling test impairment of $96.9 million ($63.0 million, net of tax). No such impairment was required in the years ended December 31, 2005 and 2004. The ceiling test calculation dictates that prices and costs in effect as of the last day of the period are to be used in calculating the discounted present value of our estimated total proved reserves. Oil and natural gas prices used in the reserve valuation at December 31, 2006 were $61.06 per barrel and $5.62 per MMbtu.

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

"Ceiling" Test - 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 prices at a measurement date could trigger a full-cost ceiling impairment. Such a reduction from June 30, 2006 to September 30, 2006 was primarily responsible for our impairment in the third quarter of 2006. Subsequent to September 30, 2006, quoted market prices for natural gas increased such that we believe we would have avoided a write down if, as would have been allowed under applicable accounting guidelines, we had elected to use such subsequent prices in calculating our ceiling test at September 30, 2006. We had a cushion (i.e. the excess of the ceiling over our capitalized costs) of $31.9 million, net of tax, at December 31, 2006. A 10% increase or decrease in prices used would have increased or decreased, respectively, our cushion by approximately 78%. Our hedging program would serve to mitigate some of the economic impact of any price decline. However, since we no longer apply cash flow hedge accounting to our derivative contracts, our hedging program does not impact the ceiling test. Had we applied cash flow hedge accounting to our outstanding derivative contracts, the cushion at December 31, 2006 would have increased by approximately $11.1 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, respectively, our cushion at December 31, 2006 by approximately 53%, net of tax. As noted above, we used pricing and costs as of the last day of the period to determine our ceiling test. Should commodity prices decrease significantly in 2007, the possibility of a ceiling test impairment at a future date exists. Also, the effects of the Smith acquisition in 2007 could increase the possibility that we will be required to record a ceiling test impairment, particularly if commodity prices decline below the effective levels paid for in the Smith acquisition.

Nature of Critical Estimate Item: Unproved Property Impairment - 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 prospects 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, 2006, we had $57.6 million allocated to unproved property. This allocation is based on our estimation of whether the property has potential attributable reserves. Therefore, our assessment 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 decreased or increased, respectively, our depletion expense by approximately 2% for the year ended December 31, 2006.

Nature of Critical Estimate Item: Asset Retirement Obligations - 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. Prior to the adoption of Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations*, the costs associated with this activity were capitalized to the full-cost pool and charged to income through depletion. 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, SFAS No. 143 requires us to estimate asset retirement costs for all of our assets, adjust those costs for inflation 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. When new obligations are incurred, i.e. new well drilled or acquired, we add a layer to the ARO liability. We accrete the liability layers quarterly using the applicable period-end effective credit-adjusted-risk-free rates for each layer. 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 well obligations are relieved by sale of the property or plugging and abandoning the well, the related liability and asset costs are removed from our 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, regulatory, 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 independent engineering firms to evaluate our properties annually. We use the remaining estimated useful life from the year-end reserve reports by our independent reserve engineers 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 are volatile, as the credit-adjusted-risk-free rate is one of the variables used on a quarterly basis. We have 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 the impact of net operating loss ("NOL") carryforwards. We routinely assess our ability to use all of our NOL carryforwards that result 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 natural gas prices). We were required to make alternative minimum tax payments for 2006 of $94,100 and for 2005 of $327,400 , but no alternative minimum tax payments were made in 2004.

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 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 revenue, 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. 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. The cash flows resulting from settlement of these hedge transactions are included in cash flows from operating activities on the statement of cash flows. While the hedge contract is outstanding, the fair value may increase or decrease until settlement of the contract. 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. During the first quarter of 2006, we discontinued cash flow hedge accounting treatment applied to our natural gas contracts due to projected changes in the 2006 physical production volumes hedged and to give us flexibility in how we market our physical production. Therefore, all contracts are utilizing mark-to-market accounting treatment rather than cash flow hedge accounting treatment at December 31, 2006, as discussed below.

Derivative Contracts - For transactions accounted for using mark-to-market accounting treatment, the change in the fair value of the derivative contract is reflected in revenue immediately, and 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 and approximates the fair value of the contracts, as the fair value obtained from our counterparties would be the cost to us to terminate a contract at that point in time. Due to the fact that we apply mark-to-market accounting treatment, the offset to the balance sheet asset or liability, or the change in fair value of the contracts, is included in revenue on the income statement rather than in OCI on the balance sheet.

Effect if different assumptions used: At December 31, 2006, 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 instruments to increase or decrease by approximately $0.6 million. Had we applied cash flow hedge accounting treatment to all of our derivative contracts outstanding at December 31, 2006, our net loss for the year would have been reduced to $33.3 million.

RESULTS OF OPERATIONS

This section includes discussion of our 2006, 2005 and 2004 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, Mississippi, Louisiana and southeast New Mexico.

Revenue and Production

Our primary source of production and revenue is natural gas. For the years ended December 31, 2006, 2005 and 2004, our product mix contributed the following percentages of revenues and production:

	REVENUES (1)		
	2006	2005	2004
Natural gas	79%	82%	82%
Natural gas liquids	4%	5%	7%
Crude oil	17%	13%	11%
Total	100%	100%	100%

(1) Includes effect of hedging and derivative transactions.

	PRODUCTION VOLUMES (MCFE)		
	2006	2005	2004
Natural gas	80%	77%	75%
Natural gas liquids	8%	11%	14%
Crude oil	12%	12%	11%
Total	100%	100%	100%

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 and availability of alternative fuels could impact worldwide supply, while the economy, weather and other factors outside of our control could impact demand.

The following table summarizes production volumes, average sales prices and operating revenue for our oil and natural gas operations for the periods indicated.

	For the Year Ended December 31,			% Increase (Decrease)	
	2006	2005	2004	06 vs. 05	05 vs. 04
Production Volumes:		*(in thousands, except prices and percentages)*			
Natural gas (Mcf)	13,850	12,597	9,148	10%	38%
Natural gas liquids (Bbls)	222	308	276	(28)%	11%
Oil and condensate (Bbls)	345	324	215	6%	51%
Natural gas equivalent (Mcfe)	17,251	16,384	12,093	5%	35%
Average Sales Price (1):					
Natural gas ($ per Mcf)(2)	$ 6.68	$ 7.97	$ 5.91	(16)%	35%
Natural gas liquids ($ per Bbl)	25.52	18.45	15.83	38%	17%
Oil and condensate ($ per Bbl) (2)	63.10	53.57	39.77	18%	35%
Natural gas equivalent ($ per Mcfe) (3)	7.52	7.40	5.33	2%	39%
Operating Revenue:					
Natural gas (2)	$ 92,582	$ 100,437	$ 54,057	(8)%	86%
Natural gas liquids	5,665	5,677	4,373	0%	30%
Oil and condensate (2)	21,767	17,336	8,535	26%	103%
Gain (loss) on hedging and derivatives	9,730	(2,267)	(2,460)	*	8%
Total (3)	$ 129,744	$ 121,183	$ 64,505	7%	88%

(1) Prices are calculated based on whole numbers, not rounded numbers.

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

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

*Not meaningful, as different accounting treatment between reporting periods affects comparability.

<u>**Natural gas revenue**</u> - Natural gas revenue, excluding hedging activity, decreased 8% for the year ended December 31, 2006 over the same period in 2005 and increased 86% for the year ended December 31, 2005 over the same period in 2004. This growth from 2004 to 2005 resulted from significantly higher production and higher realized prices, whereas the decline in natural gas revenue from 2005 to 2006 was due to lower average realized

prices that were partially offset by higher production levels. Average natural gas production increased from 25.0 MMcf/d in 2004 to 34.5 MMcf/d in 2005 and to 37.9 MMcf/d in 2006. Production increases in 2005 and 2006 as compared to 2004 have been attributable in part to significant drilling at our Queen City and southeast New Mexico properties. In addition, a significant amount of growth has come from acquisitions, including the existing production in the Queen City trend in late 2004, the Chapman Ranch Field in late 2005 and additional working interests in the Chapman Ranch Field in December of 2006, for which the impact should be more noticeable in 2007. Partially offsetting the increases in production were natural declines at our O'Connor Ranch East and Brandon projects in 2005 as compared to 2004, and natural declines in production in our older properties including Gato Creek, Encinitas and Miller in 2006 as compared to 2005. Excluding the effect of hedges, the average natural gas sales price for production in 2006 was $6.68 per Mcf compared to $7.97 per Mcf for 2005. This decrease in average price received resulted in decreased revenue of approximately $17.8 million (based on 2006 year production). The overall increase in production in 2006 compared to 2005 resulted in an increase in revenue of approximately $10.0 million (based on 2005 comparable period pre-hedge prices). The overall increase in production in 2005 compared to 2004 resulted in an increase in revenue of approximately $20.4 million (based on 2004 comparable period pre-hedge prices). Excluding the effect of hedges, the average natural gas sales price for production in 2005 was $7.97 per Mcf compared to $5.91 per Mcf for 2004. This increase in average price received resulted in increased revenue of approximately $26.0 million (based on 2005 year production).

__NGL revenue__ - Revenue from the sale of NGLs remained flat for the year ended December 31, 2006 over the same period in 2005 and increased 30% for the year ended December 31, 2005 over the same period in 2004. Daily production volumes for NGLs increased from 755 Bbls/d for the year ended December 31, 2004 to 843 Bbls/d for 2005 and decreased to 608 Bbls/d in 2006. The increase from 2004 to 2005 is primarily due to increased production from new wells drilled at Gato Creek, Encinitas, Santellana and southeast New Mexico and new processing and treating agreements entered into during 2004 which increased production in 2005. The decrease from 2005 to 2006 is mainly attributed to production declines at our Encinitas, Gato Creek and Louisiana properties. The average realized price for NGLs for the year ended December 31, 2006 was $25.52 per barrel as compared to $18.45 per barrel in 2005 and $15.83 per barrel for the same period in 2004. The increase in NGL production in 2005 increased revenue by approximately $0.5 million (based on 2004 comparable period average prices). Higher average realized prices for the year ended December 31, 2005 resulted in an increase in revenue of approximately $0.8 million (based on 2005 production).

__**Crude oil and condensate revenue**__ - Revenue from the sale of oil and condensate, excluding derivative activity, increased 26% for the year ended December 31, 2006 over the same period in 2005 and 103% for the year ended December 31, 2005 as compared to the same period in 2004 due to increased realized prices and production. The average realized price for oil and condensate before the derivative gains for the year ended December 31, 2006 was $63.10 per barrel compared to $53.57 per barrel in the same period of 2005. These higher average prices for 2006 resulted in an increase in revenue of approximately $3.3 million (based on 2006 production). The average realized price for oil and condensate before the derivative gains or losses for the year ended December 31, 2005 was $53.57 per barrel compared to $39.77 per barrel in the same period of 2004. These higher average prices for 2005 resulted in an increase in revenue of approximately $4.5 million (based on 2005 production). Production volumes for oil and condensate increased to 945 Bbls/d for the year ended December 31, 2006 from 887 Bbls/d for the same period in 2005 and 586 Bbls/d for the same period in 2004. The increase in 2006 as compared to 2005 was from production on new wells drilled in our Queen City and southeast New Mexico projects, as well as from the Chapman Ranch Field properties acquired in late 2005, partially offset by declines in production from our Miller, Encinitas, and Gato Creek properties. The increase in 2006 oil and condensate production as compared to 2005 resulted in an increase in revenue of approximately $1.1 million (based on 2005 comparable period average prices). The increase in 2005 as compared to 2004 was due primarily to successful drilling in southeast New Mexico and at our Queen City and Encinitas projects, as well as the acquisition of existing production in the Queen City trend on December 29, 2004, partially offset by declines at the Duson Horst and Brandon projects. The increase in 2005 oil and condensate production as compared to 2004 resulted in an increase in revenue of approximately $4.3 million (based on 2004 comparable period average prices).

__**Hedging and derivatives**__ - Our hedging and derivative contracts resulted in a net gain in 2006 as compared to net losses in 2004 and 2005. During the first quarter of 2006, we discontinued cash flow hedge accounting treatment applied to our natural gas collars, due to projected changes in 2006 physical production volumes hedged and to give us more flexibility in how we market our physical production. This change in accounting treatment affects the comparability of the periods (see Note 9 to our consolidated financial statements) because the change in fair market value of the natural gas hedge contracts in 2005 was deferred through OCI on the balance sheet rather than presented in total revenue on the income statement, as presented in 2006. The volume and price contract terms vary from period to period and therefore interact differently with the changing pricing environment. 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, which has proven to be a benefit to us in 2006, with declining natural gas prices resulting in cash settlement inflows from our hedge counterparties to offset the lower prices received for our physical production. The following table summarizes the various components of the total gain or loss on hedging and derivatives for each of the periods indicated and the impact each component had on our realized prices:

	Year Ended December 31,					
	2006		2005		2004	
	(in thousands, except prices)					
	$	$ per unit	$	$ per unit	$	$ per unit
Natural gas contract settlements (Mcf)	$ 4,699	$ 0.34	$ (1,230)	$ (0.10)	$ (328)	$ (0.04)
Crude oil contract settlements (Bbl)	--	--	(1,757)	(5.43)	(881)	(4.10)
Hedge premium reclassification (Mcf)	--	--	--	--	(686)	(0.08)
Mark-to-market unrealized change in fair value of gas derivative contracts (Mcf)	4,686	0.34	--	--	--	--
Mark-to-market reversal of prior period unrealized change in fair value of oil derivative contracts (Bbl)	(155)	(0.45)	565	1.74	--	--
Mark-to-market unrealized change in fair value of oil derivative contracts (Bbl)	500	1.45	155	0.48	(565)	(2.63)
Gain (loss) on hedging and derivatives (Mcfe)	$ 9,730	$ 0.56	$ (2,267)	$ (0.14)	$ (2,460)	$ (0.20)

Should crude oil or natural gas prices increase or decrease from the current levels, it could materially impact our revenues. In a high price environment, hedged positions could result in lost opportunities if there is a ceiling in place, thus lowering our effective realized prices on hedged production, but in an environment of falling prices, these transactions offer some pricing protection for hedged production. Our physical sales of these commodities are vulnerable to the volatility of market price movements. Therefore, we typically enter into contracts covering only a portion of anticipated production to ensure certain revenues that allow us to plan our business activities.

Costs and Operating Expenses

The table below presents a detail of expenses for the periods indicated:

	December 31, 2006	December 31, 2005	December 31, 2004	% Increase (Decrease) 06 vs. 05	% Increase (Decrease) 05 vs. 04
	(in thousands, except percentages)				
Oil and natural gas operating expenses	$ 9,122	$ 8,478	$ 4,946	8%	71%
Severance and ad valorem taxes	9,135	8,590	4,363	6%	97%
Depreciation, depletion, amortization and accretion:					
Oil and natural gas property and equipment	60,472	39,810	21,472	52%	85%
Other assets	419	267	357	57%	(25)%
ARO accretion	189	141	99	34%	43%
Impairment of oil and natural gas properties	96,942	--	--	*	*
General and administrative expenses:					
Bad debt expense	--	65	--	*	*
General and administrative expenses	13,788	12,371	9,447	11%	31%
Total operating expenses	190,067	69,722	40,684	173%	71%
Other expense, net	2,513	25	437	*	(94)%
Total expense	$ 192,580	$ 69,747	$ 41,121	176%	70%

* Not meaningful

<u>**Oil and natural gas operating expenses**</u> - Oil and natural gas operating expenses increased 71% between 2004 and 2005 and 8% between 2005 and 2006, an 84% increase of 2006 over 2004. The increase from 2004 to 2006 has been driven by activity increases as well as cost increases. Activity levels were impacted by bringing online 62 apparently successful wells during 2005 and 43 apparently successful wells in 2006. The 2005 and 2004 results were impacted by the addition of the Miller and south Texas properties (acquisitions late in 2003) that accounted for 26% of the total costs in 2004 and 23% in 2005. The 2005 results had the added costs from the newly acquired Contango properties (late 2004), which account for 21% of total costs in 2005 and represent 50% of the increase from 2004 to 2005. The 2006 results were impacted by increased costs on our States, Gato Creek and southeast New Mexico properties. We also experienced increases in 2006 due to the Chapman Ranch properties acquired late in 2005, but costs for this area were not as high as expected due to delays in our Chapman Ranch drilling program during 2006. Operating expenses averaged $0.53 per Mcfe, $0.52 per Mcfe and $0.41 per Mcfe for the years ended December 31, 2006, 2005 and 2004, respectively. The increasing cost structure resulted from added costs for compression, workovers and salt-water disposal as well as inflation in our industry during 2006. We are witnessing increasing costs due to increased demand for oil field products and services. The oil and natural gas industry tends to be cyclical in nature and the demand for goods and services of oil field companies, suppliers and others associated with the industry can put great pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do many or all associated costs. When commodity prices decline, associated costs do not necessarily decline at the same rate.

<u>**Severance and ad valorem taxes**</u> - Severance tax expense for 2006 was 8% lower than 2005 whereas 2005 was 76% higher than 2004. Severance taxes are levied directly on our non-hedge revenue dollars, so the trend is consistent with our changes in revenue. Total revenue subject to severance taxes in 2006 was 2% lower than 2005 and 2005 was 85% higher than 2004. The severance tax rate realized was 6.0% in 2004 and then decreased to 5.7% in 2005 and further decreased to 5.4% in 2006. The rate realized changes as a result of the changing mix of our production locations. We had a significant portion of production in Texas in 2004, which imposes a tax rate of approximately 7.5% of the revenue dollar. In 2005, we had an increasing amount of production in New Mexico which added another location to the mix. In 2006, we received severance tax abatements on certain Chapman Ranch Field locations acquired late in 2005 as a result of these properties qualifying for high-cost gas certification, which lowered our severance tax rate further. Ad valorem costs increased 67% in 2006 as compared to 2005 and increased

296% in 2005 compared to 2004. Increased commodity prices in 2005 and 2006 resulted in a higher valuation of reserves by taxing authorities and therefore higher ad valorem taxes on certain properties. Significant property acquisitions in late 2004 led to increased ad valorem taxes in 2005 and represented the majority of the increase from 2004 to 2005. On an equivalent basis, severance and ad valorem taxes averaged $0.53 per Mcfe, $0.52 per Mcfe and $0.36 per Mcfe for the years ended December 31, 2006, 2005 and 2004, respectively.

Depletion, depreciation and amortization ("DD&A") and accretion expense - DD&A and accretion expense for the year ended December 31, 2006 increased 52% over the year ended December 31, 2005 and 83% for the year ended December 31, 2005 over the year ended December 31, 2004. Full-cost depletion on our oil and natural gas properties totaled $60.5 million in 2006, $39.8 million in 2005 and $21.5 million in 2004. These increases were driven by production volume increases in 2004 and depletion rate increases in 2005 and 2006. For the year ended December 31, 2006, depletion expense on a unit of production basis was $3.51 per Mcfe or 44% higher than the 2005 depletion rate of $2.43. The higher depletion rate increased depletion expense by approximately $18.6 million. Higher production in 2006 compared to 2005 increased depletion expense by approximately $2.1 million. For the year ended December 31, 2005, higher oil and natural gas production compared to the prior year period resulted in an increase in depletion expense of $7.6 million. Depletion expense on a unit of production basis for the year ended December 31, 2005 was $2.43 per Mcfe, 37% higher than the 2004 rate of $1.78 per Mcfe. The higher depletion rate per Mcfe resulted in an increase in depletion expense of $10.7 million. The increase in the depletion rate was primarily due to a higher amortizable base in 2005 compared to the prior year without a corresponding increase in reserves.

Depreciation of other assets increased 57% from 2005 to 2006 and decreased 25% from 2004 to 2005. Our depreciation expense related to other assets increased from 2005 to 2006 because we fully depreciated computer software programs during the year and then replaced those same programs with new, upgraded technology. From 2004 to 2005 a decrease in depreciation expense occurred due to accelerating depreciation on leasehold improvements and computer equipment in 2003 and 2004.

Accretion expense on our ARO liability increased 34% in 2006 and 43% in 2005 for the addition of new obligations associated with wells added each year, 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.

Impairment of oil and natural gas properties – During the third quarter of 2006 we recorded a non-cash full-cost ceiling test impairment of oil and natural gas properties in the amount of $96.9 million ($63.0 million, net of tax), as discussed in Note 2 to the consolidated financial statements. No such impairment was necessary in 2005 or 2004. The write-down was primarily the result of the decline in natural gas prices at September 30, 2006. The natural gas price used to calculate the full-cost ceiling at September 30, 2006 was significantly lower than the price at year-end 2005 and 2004 when no impairment was necessary.

General and administrative ("G&A") expenses - Total G&A expenses for the year ended December 31, 2006 were $13.8 million, an increase of 11% compared to the 2005 total of $12.4 million and 46% compared to the 2004 total of $9.4 million. The components of total G&A for 2004 and 2005 include compensation costs in accordance with FIN 44 related to repriced options, amortization of restricted stock grants, bad debt expense and other corporate G&A costs. In 2006, in conjunction with the adoption of SFAS No. 123(R), we discontinued the application of FIN 44 accounting treatment for repriced options and began recording compensation expense for stock options that had not vested as of the date of adoption of SFAS No. 123(R).

In 2004 and 2005, FIN 44 accounting treatment was applied to our repriced options, which calls 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 repriced 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. In 2004 and 2005, we adjusted compensation expense upward or downward monthly based on the trading price at the end of each such period. We were required to report under this rule as a result of non-qualified stock options granted to employees and directors in prior years and repriced in May of 1999, as well as certain newly issued options in conjunction with the repricing. A FIN 44 charge on our repriced stock options was required in 2004 and 2005 as a result of our stock price exceeding the exercise price of those repriced options. The average price at December 31, 2005 and 2004 that was used to calculate this expense was $24.65 per share and $14.66 per share, respectively. In conjunction with the adoption of SFAS No. 123(R), we discontinued the application of FIN 44 and there will not be any additional adjustments for charges or credits to compensation expense related to repriced options.

Upon adoption of SFAS No. 123(R), as discussed in Notes 2 and 17 to the consolidated financial statements, during 2006, we recorded $68,937 in compensation expense for stock options that had not vested as of adoption of SFAS No. 123(R). Those options have since vested and we have not issued new options since 2004.

Compensation expense related to the amortization of restricted stock has increased from $0.5 million in 2004 to $1.0 million in 2005 and to $1.9 million in 2006. This gradual increase in compensation for restricted stock awards is related to additional restricted stock awards granted in conjunction with our increase in employees from 2004 to 2006 as well as the vesting of additional tranches of grants already awarded to existing employees.

Other G&A expenses, which does not include the compensation costs discussed above, increased 20% over 2005, which was 25% higher than 2004. The increase in other G&A from 2004 to 2006 was in part attributable to the growth in our company from 51 full-time employees at December 31, 2004 to 68 full-time employees and one part-time employee at December 31, 2006. In 2005, we added new corporate office space to support our growth, which increased our rent expense. We also were impacted by higher audit and legal fees and amounts spent on investor relations projects during 2005. In 2005, we realized additional costs related to the 2004 Sarbanes-Oxley 404 Internal Control Report of approximately $92,700 that were unexpected. These increases were partially offset by decreases in general office related spending in 2004. Included in 2005 were charitable contributions of $100,000 to the Hurricane Katrina relief effort and bad debt expense of $65,157 for joint interest owner accounts receivable that we believe were uncollectible. In 2006, we experienced higher legal fees which were in conjunction with increased legal activity in Texas and Louisiana. Also in 2006, we paid a franchise tax settlement to the State of Texas of approximately $0.2 million and a litigation settlement in the Broussard case of approximately $0.2 million (see Note 13 to the consolidated financial statements). For the years ended December 31, 2006, 2005 and 2004, overhead reimbursement fees reduced G&A costs by approximately $429,600, $287,900 and $262,000, respectively. We capitalized $3.0 million, $2.6 million and $2.2 million of general and administrative costs in 2006, 2005 and 2004, respectively. Other G&A expenses on a unit of production basis for the years ended December 31, 2006, 2005 and 2004 were $0.68 per Mcfe, $0.60 per Mcfe and $0.65 per Mcfe, respectively.

Other income (expense) – For the years ended December 31, 2004 and 2006, we capitalized a portion of our interest expense. But in the year ended December 31, 2005, we capitalized 100% of our interest expense because our unproved property balance exceeded our weighted average debt balance. At December 31, 2006, 2005 and 2004 our unproved property balance was $57.6 million, $36.9 million and $15.5 million, respectively. We incurred higher interest costs for the year ended December 31, 2006 than for the years 2005 and 2004 due to higher commitment fees and outstanding debt balances, and also due to interest paid on our franchise tax settlement in 2006 of approximately $40,150. Interest costs on the franchise tax settlement were not subject to capitalization. The table below details our interest expense, capitalized interest and weighted average debt for each of the periods indicated:

	For the Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Gross interest	$ 7,761	$ 1,943	$ 1,033
Less: capitalized interest	(5,261)	(1,943)	(702)
Interest expense, net	$ 2,500	$ --	$ 331
Weighted Average Debt	$ 102,077	$ 24,189	$ 20,027

Included in other income (expense) for the years ended December 31, 2006, 2005 and 2004 was $165,211, $152,723 and $142,135, respectively, representing amortization of deferred loan costs associated with our then-existing credit facility.

Also included in other income (expense) was interest income, which totaled $152,184, $127,993, and $36,075 for the years ended December 31, 2006, 2005 and 2004, respectively. The interest is earned on daily cash invested in overnight money market funds. We have had increased cash on hand in recent years providing for the increased interest income.

Income tax expense/benefit - We are subject to state and federal income taxes and although we were recently generating taxable income for financial reporting purposes, we are not in a federal income tax paying position as a result of deducting intangible drilling costs ("IDC") that reduce our taxable income for income tax purposes and NOL carryforwards that offset any remaining taxable income. A deferred income tax benefit of $21.6 million was recorded for the year ended December 31, 2006, as we reported a net loss for the year, primarily due to the full-cost ceiling test impairment recorded in the third quarter of 2006. Deferred income tax provisions of $18.1 million and $8.3 million were recorded for the years ended December 31, 2005 and 2004, respectively. The majority of the increase year over year has been the growth in income before income taxes. Due to changes in amounts of permanent tax differences, including meals and entertainment and compensation expense, our effective tax rate also changes from time to time. The effective rate was 34.3% for the year ended December 31, 2006, as compared to 35.2% in 2005 and 35.3% in 2004. As of December 31, 2006, approximately $73.6 million of net operating loss carryforwards have been accumulated or acquired that will begin to expire in 2012. We were required to make alternative minimum tax payments for 2006 of $94,100 and of $327,400 in 2005. No such alternative minimum tax payments were made in 2004.

Earnings/loss per share - For the year ended December 31, 2006, we had a net loss of $41.3 million, or $2.38 per basic and diluted loss per share, as compared to net income of $33.4 million, or $1.95 basic earnings per share and $1.87 diluted earnings per share, in the same period of 2005 and net income of $15.1 million, or $1.16 basic and $1.11 diluted earnings per share, in 2004. Basic weighted average shares outstanding increased from approximately 13.0 million at December 31, 2004 to 17.1 million at December 31, 2005 and to 17.4 million at December 31, 2006. There were also minimal increases due to options exercised and vesting of restricted stock during 2004, 2005 and 2006.

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 and commodity prices, both of which are inherently volatile and unpredictable, as well as operating efficiency and capital spending. Our business, as with other extractive businesses, is a depleting one in which each gas equivalent unit produced must be replaced or our asset base and capacity to generate revenues in the future will shrink. Our overall expected future production decline is estimated to be approximately 22% per year. 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.

Our primary cash requirements 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 have historically used our credit facility to supplement any deficiencies between operating cash flow and capital expenditures. We typically have funded acquisitions from borrowings under our credit facility, cash flow from operations and sales of common stock and preferred stock.

Significant changes to working capital may affect our liquidity in the short term. The increase in our derivative instrument asset is indicative of potential future cash settlement inflows on our hedge positions, which are scheduled to settle in future months. The fair value of our outstanding derivative contracts is reflected on the balance sheet as a current asset and a long-term liability for the positions with each of our two counterparties. Our derivative financial instrument asset represents future potential cash inflows as of the balance sheet date, such that if the contracts were to settle at the balance sheet date we would have significant potential gains. The fair market value represents the potential settlement for those contracts if the market prices remain unchanged, but should commodity prices increase or decrease, the fair value of those outstanding contracts would change and the settlements at maturity would also change. When our derivatives result in cash inflows on settlements, we receive lower cash inflows on the sale of unhedged production at lower market prices, thus providing us with fewer funds with which to cover any derivative payments that may come due in the future.

We have historically used our credit facility to supplement any deficiencies between operating cash flow and capital expenditures. Our outstanding debt balance has increased from $20.0 million at December 31, 2004, to $85.0 million at year-end 2005, to $129.0 million at December 31, 2006, and to $235.0 million at March 9, 2007, primarily due to the funding of our acquisition program, principally the 2005 and 2006 acquisitions in the Chapman Ranch field, through borrowings under our then-existing credit facility.

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 under our credit facility, combined with our ability to control the timing of certain of our future exploration and development requirements, will provide us with the flexibility and liquidity to meet our planned capital requirements for 2007. Our new revolving credit facility had $85.0 million available for borrowing at March 9, 2007.

During 2004 and early 2005, we realized increased cash flows as a result of our public stock offerings and exercises of options and warrants to acquire shares of our common stock. Most significant were the net proceeds of $47.8 million that we received, before direct costs of $0.6 million, from our December 2004 offering of our common stock and the related exercise of the underwriter's over-allotment option for 0.5 million additional shares of our common stock, resulting in an additional $7.2 million of net proceeds to us in January 2005. At December 31, 2005 and 2006, we had certain options outstanding and exercisable for shares of our common stock. We typically do not rely on proceeds from the exercise of warrants and stock options to sustain our business, as the timing of their exercise is unpredictable.

We had cash and cash equivalents at December 31, 2006 of $2.1 million consisting primarily of short-term money market investments, as compared to $0.7 million at December 31, 2005. Working capital was $10.2 million as of December 31, 2006, as compared to $10.5 million at December 31, 2005.

	For the Year Ended December 31,		
	2006	**2005**	**2004**
		(in thousands)	
Net Cash Provided By Operating Activities	$ 97,409	$ 93,111	$ 42,270
Net Cash Used In Investing Activities	(140,412)	(167,280)	(89,410)
Net Cash Provided by Financing Activities	44,418	72,568	48,080

Net Cash Provided By Operating Activities - Cash flows provided by operating activities were $97.4 million, $93.1 million and $42.3 million for the years ended December 31, 2006, 2005, and 2004, respectively. The significant increase in cash flows provided by operating activities for the year ended December 31, 2005 compared to 2004 was primarily due to higher oil and gas production revenue partially offset by higher operating expense, and the increase from 2005 to 2006 occurred for the same reasons, only to a lesser extent.

Net cash generated from operating activities is a function of commodity prices, which are inherently volatile and unpredictable, production and capital spending. In an effort to reduce the volatility realized on commodity prices, we enter into derivative instruments. Due to lower natural gas market pricing, we realized a benefit in cash settlement gains of $4.7 million on our natural gas derivatives during 2006. Overall, oil and gas production revenue for 2006 increased 7% over 2005 and 101% over 2004.

Although fluctuations in commodity prices have been the primary reason for our short-term changes in cash flow from operating activities, increased production volumes also impacted us in 2006. Our business, as with other extractive businesses, is a depleting one in which each gas equivalent produced must be replaced or our asset base and capacity to generate revenues in the future 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 put in place an annual budget that is based upon our forecasts for production, revenues and costs. Those forecasts are reviewed and updated regularly by management and our capital budget is adjusted as warranted. Longer term forecasts are used to assist our strategic planning and long-term capital planning.

In the event such capital resources are not available to us, our drilling and other activities may be curtailed. See *ITEMS 1A. "RISK FACTORS* – Our operations have significant capital requirements which, if not met will hinder operations."

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 $140.4 million in investing activities during 2006. Capital expenditures of $82.6 million were attributable to the drilling of 52 gross wells, 43 of which were apparently successful. Acquisition costs totaled $39.4 million, mainly related to the acquisition of additional interests in the Chapman Ranch Field late in 2006 and final adjustments to the Cinco purchase price. Other spending included $14.0 million attributable to land holdings, capitalized G&A and interest and $7.7 million for increased seismic data and other geological and geophysical expenditures. Drilling advances to the operator of our Queen City properties decreased in 2006 to approximately $2.9 million. We also received $0.6 million during 2006 from the sale of our Buckeye properties. The remaining capital expenditures were associated with computer hardware and office furniture and equipment.

During the year ended December 31, 2005, we used $167.3 million in investing activities. Capital expenditures of $79.1 million were attributable to the drilling of 65 gross wells, 62 of which were apparently successful. Acquisition costs related to the private company corporate acquisition totaled $39.0 million, net of cash acquired, and other acquisition costs totaled $28.0 million, mainly related to the Chapman Ranch Field asset acquisition. Other spending included $14.4 million attributable to land holdings, capitalized G&A and interest and $2.5 million for increased seismic data and other geological and geophysical expenditures. Drilling advances to the operator of our Queen City properties amounted to $4.3 million during 2005. 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, 2004, we used $89.4 million in investing activities. 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 included $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.

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 2007 to be approximately $140 million. Approximately $111.0 million is allocated to our expected drilling and production activities; $21.0 million is allocated to land, legal and seismic activities; and $8.0 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 sources. Should there be a change in our pricing or production assumptions, we believe that we have sufficient financial flexibility from other financing sources 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 $44.4 million for the year ended December 31, 2006. We had $62.0 million in borrowings and $18.0 million in repayments under our credit facility. We incurred loan costs of approximately $0.2 million in amending our credit facility. In addition, we received $0.6 million in proceeds from the issuance of common stock related to options exercised in 2006.

For the year ended December 31, 2005, cash flows provided by financing activities totaled $72.6 million. We had $81.0 million in borrowings and $16.0 million in repayments under our credit facility. We incurred loan costs of approximately $47,000 in amending our credit facility. In addition, we received $7.6 million in proceeds from the issuance of common stock related to options exercised in 2005. The majority of those proceeds are related to the January 2005 underwriter exercise of the over-allotment option to the December 2004 common stock offering. The funds generated from that exercise were used to reduce debt early in 2005.

For the year ended December 31, 2004, cash flows provided by financing activities totaled $48.1 million including $27.0 million in borrowings and $28.0 million in repayments under our credit facility. In addition, we completed a public offering of common stock in December 2004 that provided $47.2 million of net proceeds, after direct costs. We also received approximately $2.3 million in proceeds from exercised stock options and warrants, and incurred approximately $0.4 million in loan costs in 2004.

The combination of unused debt capacity and possible sales of equity or debt securities should allow us the financial flexibility to continue to participate in acquisitions and complete our capital programs as we move into 2007.

Credit Facility

On December 21, 2006, we amended our Third Amended and Restated Credit Agreement (the "Prior Credit Facility"), which we had originally entered into in March 2004 (effective December 31, 2003) and previously amended on December 4, 2006. The Prior Credit Facility permitted borrowings up to the lesser of (i) the borrowing base and (ii) $150.0 million. Effective December 2006, the borrowing base under the Prior Credit Facility was increased from $125.0 million to $140.0 million as a result of acquisitions and our drilling activities since the last redetermination. Based on the increase, our available borrowing capacity at December 31, 2006 was $11.0 million.

The Prior Credit Facility's scheduled maturity date was March 31, 2008, and it was secured by substantially all of our assets. Borrowings under the Prior Credit Facility bore interest at rates that were variable based on the percentage usage of the facility. Borrowings could be at Prime plus a margin of up to 0.25% or at LIBOR plus a margin of 1.75% to 2.125%. As of December 31, 2006, our interest rates on our outstanding Prime and LIBOR borrowings were 8.500% and 7.485%, respectively. As of December 31, 2006, $129.0 million in borrowings were outstanding under the Prior Credit Facility.

The Prior Credit Facility provided for certain restrictions and covenants, 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 Prior Credit Facility also prohibited dividends on our common stock and certain distributions of cash or properties and certain liens. The Prior Credit Facility also contained the following financial covenants, among others:

- The EBITDAX to Interest Expense ratio required 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 required that the amount of our consolidated current assets less our consolidated current liabilities, as defined in the Credit Facility Agreement, be at least $1.0 million. For the purposes of calculating the Working Capital ratio, the total of current assets was adjusted for unused capacity under the Credit Facility Agreement, and derivative financial instruments and the total of current liabilities was adjusted for the current portion of indebtedness under the Credit Facility Agreement, derivative financial instruments and asset retirement obligations.
- The Maximum Leverage ratio required that the ratio, as of the last day of any fiscal quarter, of (a) Total Indebtedness (as defined in the Credit Facility Agreement) 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 lenders and is defined above as part of our disclosure of our covenant obligations.

As discussed in Note 12 to our consolidated financial statements, subsequent to year-end on January 30, 2007, the Company entered into a Fourth Amended and Restated Credit Agreement (the "Agreement") for a new Revolving Credit Facility with Union Bank of California ("UBOC"), as administrative agent and issuing lender, and the other lenders party thereto. Pursuant to the Agreement, UBOC will act as the administrative agent for a senior, first lien secured borrowing base revolving credit facility (the "Credit Facility") in favor of us and certain of our wholly owned subsidiaries (which subsidiaries include Edge Petroleum Operating Company, Inc., Edge Petroleum Exploration Company, Miller Oil Corporation and Miller Exploration Company) in an amount equal to $750 million, of which only $320 million is available under the borrowing base established at the closing. The Credit Facility has a letter of credit sub-limit of $20 million. In connection with the Credit Facility, we paid the lenders fees in an amount equal to 1.00% of the initial borrowing base established under the Credit Facility, or $3.2 million, on January 31, 2007. We paid approximately $0.4 million to the lenders for certain other administrative fees, fronting fees and work fees in connection with the Credit Facility. Upon initiation of the Credit Facility, we terminated our existing Third Amended and Restated Credit Agreement described above and repaid the $129.0 million in borrowings under the Prior Credit Facility with proceeds from the public offerings described below and in Note 12 to the consolidated financial statements.

The Credit Facility matures on January 31, 2011 and bears interest at LIBOR plus an applicable margin ranging from 1.25% to 2.5%, with an unused commitment fee ranging from 0.50% to 0.25%.

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 restricts dividends and certain distributions of cash or properties and certain liens and also contains financial covenants including, without limitation, the following:

- An EBITDAX to interest expense ratio requires that as of the last day of each fiscal quarter the ratio of (a) our consolidated EBITDAX (defined as EBITDA plus similar non-cash items and exploration and abandonment expenses for such period) to (b) our consolidated interest expense, not be less than 2.5 to 1.0, calculated on a cumulative quarterly basis for the first 12 months after the closing of the Credit Facility and then on a rolling four quarter basis.

- A current ratio requires that as of the last day of each fiscal quarter the ratio of our consolidated current assets to our consolidated current liabilities, as defined in the Credit Facility, be at least 1.0 to 1.0.

- A maximum leverage ratio requires that as of the last day of each fiscal quarter the ratio of (a) Total Indebtedness (as defined in the Credit Facility) to (b) an amount equal to consolidated EBITDAX be not greater than 3.0 to 1.0, calculated on a cumulative quarterly basis for the first 12 months after the closing of the Credit Facility and then on a rolling four quarter basis.

The Credit Facility includes other covenants and events of default that we believe are customary for similar facilities. As of March 9, 2007, $235.0 million in borrowings were outstanding under the Credit Facility, as a result of the Smith acquisition and the refinancing of the Prior Credit Facility.

Shelf Registration Statement

During the second quarter 2005, we filed a registration statement with the SEC which registered offerings of up to $390.0 million of any combination of debt securities, preferred stock, common stock or warrants for debt securities or equity securities of the Company. 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. In connection with the filing of the 2005 registration statement, we deregistered the remaining shares then available for sale under our earlier $150.0 million shelf registration statement filed in 2004.

On December 21, 2004, we completed an offering of 3.5 million shares of our common stock, which generated net proceeds to us, before direct costs of the offering, of $47.8 million. These funds were used to finance the south Texas asset acquisition that closed on December 29, 2004 with a final adjusted purchase price of $40.1 million, before other acquisition costs, 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. At December 31, 2006, we had $390.0 million remaining for issuance under our 2005 shelf registration statement.

As discussed in Note 12 to our consolidated financial statements, we completed a public offering of 10.925 million shares of common stock and 2.875 million shares of Series A cumulative convertible perpetual preferred stock subsequent to year-end. These offerings generated combined estimated net proceeds to us, before direct costs of the offerings, of $276.7 million ($138.1 million in the common offering and $138.6 million in the preferred offering). These proceeds were used to partially finance the Smith acquisition, which closed on January 31, 2007, and to refinance our Prior Credit Facility. At March 9, 2007, we had approximately $101.5 million remaining available for issuance under our 2005 shelf registration statement.

Convertible Preferred Stock

In January 2007, we completed the public offering of 2,875,000 shares of our 5.75% Series A cumulative convertible perpetual preferred stock ("Convertible Preferred Stock") for net proceeds of approximately $138 million. We used the proceeds from this offering, along with the proceeds from a concurrent common stock offering and along with borrowings under our current credit facility, to finance the Smith acquisition and to refinance our prior credit facility.

Dividends. The Convertible Preferred Stock accumulates dividends at a rate of $2.875 for each share of Convertible Preferred Stock per year. Dividends are cumulative from the date of first issuance and, to the extent payment of dividends is not prohibited by our debt agreements, assets are legally available to pay dividends and our board of directors or an authorized committee of our board declares a dividend payable, we will pay dividends in cash, every quarter.

No dividends or other distributions (other than a dividend payable solely in shares of a like or junior ranking) may be paid or set apart for payment upon any shares ranking equally with the Convertible Preferred Stock ("parity shares") or shares ranking junior to the Convertible Preferred Stock ("junior shares"), nor may any parity shares or junior shares be redeemed or acquired for any consideration by us (except by conversion into or exchange for shares of a like or junior ranking) unless all accumulated and unpaid dividends have been paid or funds therefore have been set apart on the Convertible Preferred Stock and any parity shares.

Liquidation preference. In the event of our voluntary or involuntary liquidation, winding-up or dissolution, each holder of Convertible Preferred Stock will be entitled to receive and to be paid out of our assets available for distribution to our stockholders, before any payment or distribution is made to holders of junior stock (including common stock), but after any distribution on any of our indebtedness or senior stock, a liquidation preference in the amount of $50 per share of the Convertible Preferred Stock, plus accumulated and unpaid dividends on the shares to the date fixed for liquidation, winding-up or dissolution.

Ranking. Our Convertible Preferred Stock ranks:

- senior to all of the shares of our common stock and to all of our other capital stock issued in the future unless the terms of such capital stock expressly provide that it ranks senior to, or on a parity with, shares of our Convertible Preferred Stock;
- on a parity with all of our other capital stock issued in the future the terms of which expressly provide that it will rank on a parity with the shares of our Convertible Preferred Stock; and
- junior to all of our existing and future debt obligations and to all shares of our capital stock issued in the future the terms of which expressly provide that such shares will rank senior to the shares of our Convertible Preferred Stock.

Mandatory conversion. On or after January 20, 2010, we may, at our option, cause shares of our Convertible Preferred Stock to be automatically converted at the applicable conversion rate, but only if the closing sale price of our common stock for 20 trading days within a period of 30 consecutive trading days ending on the trading day immediately preceding the date we give the conversion notice equals or exceeds 130% of the conversion price in effect on each such trading day.

Optional redemption. If fewer than 15% of the shares of Convertible Preferred Stock issued in the Convertible Preferred Stock offering (including any additional shares issued pursuant to the underwriters' over-allotment option) are outstanding, we may, at any time on or after January 20, 2010, at our option, redeem for cash all such Convertible Preferred Stock at a redemption price equal to the liquidation preference of $50 plus any accrued and unpaid dividends, if any, on a share of Convertible Preferred Stock to, but excluding, the redemption date, for each share of Convertible Preferred Stock.

Conversion rights. Each share of Convertible Preferred Stock may be converted at any time, at the option of the holder, into approximately 3.0193 shares of our common stock (which is based on an initial conversion price of $16.56 per share of common stock, subject to adjustment) plus cash in lieu of fractional shares, subject to our right to settle all or a portion of any such conversion in cash or shares of our common stock. If we elect to settle all or any portion of our conversion obligation in cash, the conversion value and the number of shares of our common stock we will deliver upon conversion (if any) will be based upon a 20 trading day averaging period.

Upon any conversion, the holder will not receive any cash payment representing accumulated and unpaid dividends on the Convertible Preferred Stock, whether or not in arrears, except in limited circumstances. The conversion rate is equal to $50 divided by the conversion price at the time. The conversion price is subject to adjustment upon the occurrence of certain events. The conversion price on the conversion date and the number of shares of our common stock, as applicable, to be delivered upon conversion may be adjusted if certain events occur.

Purchase upon fundamental change. If we become subject to a fundamental change (as defined herein), each holder of shares of Convertible Preferred Stock will have the right to require us to purchase any or all of its shares at a purchase price equal to 100% of the liquidation preference, plus accumulated and unpaid dividends, to the date of the purchase. We will have the option to pay the purchase price in cash, shares of common stock or a combination of cash and shares. Our ability to purchase all or a portion of the Convertible Preferred Stock for cash is subject to our obligation to repay or repurchase any outstanding debt required to be repaid or repurchased in connection with a fundamental change and to any contractual restrictions then contained in our debt.

Conversion in connection with a fundamental change. If a holder elects to convert its shares of our Convertible Preferred Stock in connection with certain fundamental changes, we will in certain circumstances increase the conversion rate for such Convertible Preferred Stock. Upon a conversion in connection with a fundamental change, the holder will be entitled to receive a cash payment for all accumulated and unpaid dividends.

A "fundamental change" will be deemed to have occurred upon the occurrence of any of the following:

1. a "person" or "group" subject to specified exceptions, disclosing that the person or group has become the direct or indirect ultimate "beneficial owner" of our common equity representing more than 50% of the voting power of our common equity other than a filing with a disclosure relating to a transaction which complies with the proviso in subsection 2 below;

2. consummation of any share exchange, consolidation or merger of us pursuant to which our common stock will be converted into cash, securities or other property or any sale, lease or other transfer in one transaction or a series of transactions of all or substantially all of the consolidated assets of us and our subsidiaries, taken as a whole, to any person other than one of our subsidiaries; provided, however, that a transaction where the holders of more than 50% of all classes of our common equity immediately prior to the transaction own, directly or indirectly, more than 50% of all classes of common equity of the continuing or surviving corporation or transferee immediately after the event shall not be a fundamental change;

3. we are liquidated or dissolved or holders of our capital stock approve any plan or proposal for our liquidation or dissolution; or

4. our common stock is neither listed on a national securities exchange nor listed nor approved for quotation on an over-the-counter market in the United States.

However, a fundamental change will not be deemed to have occurred in the case of a share exchange, merger or consolidation, or in an exchange offer having the result described in subsection 1 above, if 90% or more of the consideration in the aggregate paid for common stock (and excluding cash payments for fractional shares and cash payments pursuant to dissenters' appraisal rights) in the share exchange, merger or consolidation or exchange offer consists of common stock of a United States company traded on a national securities exchange (or which will be so traded or quoted when issued or exchanged in connection with such transaction).

Voting rights. If we fail to pay dividends for six quarterly dividend periods (whether or not consecutive) or if we fail to pay the purchase price on the purchase date for the Convertible Preferred Stock following a fundamental change, holders of our Convertible Preferred Stock will have voting rights to elect two directors to our board.

In addition, we may generally not, without the approval of the holders of at least 66 2/3% of the shares of our Convertible Preferred Stock then outstanding:

- amend our restated certificate of incorporation, as amended, by merger or otherwise, if the amendment would alter or change the powers, preferences, privileges or rights of the holders of shares of our Convertible Preferred Stock so as to adversely affect them;

- issue, authorize or increase the authorized amount of, or issue or authorize any obligation or security convertible into or evidencing a right to purchase, any senior stock; or

- reclassify any of our authorized stock into any senior stock of any class, or any obligation or security convertible into or evidencing a right to purchase any senior stock.

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, 2006 by payment due date:

	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
			(in thousands)		
Long-term debt (1)	$ 129,000	$ --	$ 129,000	$ --	$ --
Operating leases	5,354	817	2,460	1,608	469
Total contractual cash obligations (2)(3)	$ 134,354	$ 817	$ 131,460	$ 1,608	$ 469

(1) Excludes amounts for interest expense payable upon outstanding debt. Long-term outstanding debt 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. We do not forecast debt repayments beyond the current year. Therefore, cash payments for interest beyond one year cannot be estimated. We expect to pay approximately $19.1 million in interest during 2007.

(2) We did not have any capital leases or purchase obligations as of December 31, 2006.

(3) We have not included our 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 AND HEDGING

Due to the volatility 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 to commodity price fluctuations. While the use of these arrangements may 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 limit our potential gains from future increases in prices. 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* (as amended). These derivative instruments are intended to hedge our price risk and may be considered hedges for economic purposes. There are two types of accounting treatments for derivatives, (i) mark-to-market accounting and (ii) cash flow hedge accounting. For discussion of these accounting treatments, see Note 9 to our consolidated financial statements. During the first quarter of 2006, we discontinued cash flow hedge accounting treatment previously applied to our natural gas derivatives. Therefore, all derivatives are recorded on the balance sheet at fair value and the changes in fair value are presented in total revenue on the income statement, rather than deferred through OCI on the balance sheet. The following table provides additional information regarding our various derivative transactions that were recorded at fair value on the balance sheet as of December 31, 2006.

Fair value of contracts outstanding at December 31, 2005	$	(2,479)
Contracts realized or otherwise settled during the period		4,699
Fair value of new contracts when entered into during 2006:		
Asset		5,733
Liability		(546)
Changes in fair values attributable to changes in valuation techniques and assumptions		--
Other changes in fair values		(2,220)
Fair values of contracts outstanding at December 31, 2006	$	5,187

The following table details the fair value of our commodity-based derivative contracts by year of maturity and valuation methodology as of December 31, 2006.

	Fair Value of Contracts at December 31, 2006				
Source of Fair Value	**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	5,945	--	--	--	5,945
Liability	--	(758)	--	--	(758)
Prices based on models and other valuation methods:	--	--	--	--	--
Total	$ 5,945	$ (758)	$ --	$ --	$ 5,187

TAX MATTERS

At December 31, 2006, we have cumulative net operating loss carryforwards ("NOLs") for federal income tax purposes of approximately $73.6 million, including $17.4 million and $5.4 million of NOLs acquired in the Miller merger and Cinco acquisition, respectively, that expire beginning in 2012. These estimated NOLs 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 March 2006, the FASB issued SFAS No. 156, *Accounting for Servicing of Financial Assets*, which requires all separately recognized servicing assets and servicing liabilities be initially measured at fair value. SFAS No. 156 permits, but does not require, the subsequent measurement of servicing assets and servicing liabilities at fair value. Adoption is required as of the beginning of the first fiscal year that begins after September 15, 2006. Early adoption is permitted. The adoption of SFAS No. 156 is not expected to have a material effect on our consolidated financial position, results of operations or cash flows.

In June 2006, the FASB issued FIN 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109*, which clarifies the accounting for uncertainty in income taxes recognized in accordance with SFAS No. 109, *Accounting for Income Taxes*. FIN 48 prescribes a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, no benefit will be recorded. FIN 48 also requires that the amount of interest expense to be recognized related to uncertain tax positions be computed by applying the applicable statutory rate of interest to the difference between the tax position recognized in accordance with FIN 48 and the amount previously taken or expected to be taken in a tax return. The change in net assets as a result of applying this pronouncement will be considered a change in accounting principle, with the cumulative effect of the change treated as an offsetting adjustment to the opening balance of retained earnings or goodwill, if allowed under existing accounting standards, in the period of transition. FIN 48 is effective as of January 1, 2007 and we are currently evaluating the effects, if any, that FIN 48 will have on our financial statements.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which provides guidance for using fair value to measure assets and liabilities. The standard also gives expanded information about the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect of fair value measurements on earnings. SFAS No. 157 does not expand the use of fair value in any new circumstances. SFAS No. 157 establishes a fair value hierarchy that prioritizes the information used to develop fair value assumptions. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. Early adoption is encouraged. We are currently assessing the impact, if any, that SFAS No. 157 will have on our financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, which permits entities to choose to measure many financial instruments and certain other items at fair value.. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 applies to all entities and is effective for fiscal years beginning after November 15, 2007. We are currently determining the impact, if any, that SFAS No. 159 will have on our financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE 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 provides 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, 2006 outstanding borrowings and interest rates of 8.500% and 7.485% applied to various borrowings, a 10% change in interest rate would result in an increase or decrease in interest expense of approximately $1.0 million on an annual basis.

In the normal course of business, we enter into derivative transactions, including commodity price collars, swaps and floors to mitigate our exposure to commodity price movements, but not for trading or speculative purposes. During 2006 and early 2007, we put in place several natural gas and crude oil collars for a portion of our 2007 and 2008 production to achieve a more predictable cash flow. Please refer to Note 9 to our consolidated financial statements for a discussion of these collars. 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, 2006:

Transaction Date	Transaction Type	Beginning		Ending	Price Per Unit	Volumes Per Day		Fair Value Outstanding as of December 31, 2006
Natural Gas (1):								*(in thousands)*
08/06	Collar	01/01/07	(3)	12/31/07	$7.50-$11.50	5,000 MMbtu	$	2,301
08/06	Collar	01/01/07	(3)	12/31/07	$7.50-$12.00	5,000 MMbtu		2,385
Crude Oil (2):								
08/06	Collar	01/01/07		12/31/07	$70.00-$87.50	400 Bbl		1,047
12/06	Swap	01/01/07		12/31/07	$66.00	600 Bbl		212
12/06	Swap	01/01/08		12/31/08	$66.00	1,500 Bbl		(758)
							$	5,187

(1) Our current natural gas collars were entered into on a per MMbtu delivered price basis, using the Houston Ship Channel Index. During 2005, cash flow hedge accounting was applied to these contracts, which was then discontinued in 2006. During 2006, mark-to-market accounting treatment was applied to these contracts and the change in fair value is reflected in total revenue during the year.

(2) Cash flow hedge accounting is not applied to our crude oil contracts, which were entered into on a per barrel delivered price basis, using the West Texas Intermediate Light Sweet Crude Oil Index. Mark-to-market accounting treatment is applied to these contracts and the change in fair value is reflected in total revenue during the year.

(3) Subsequent to December 31, 2006, two natural gas collars covering a portion of our 2007 estimated production were terminated and replaced with new collars. The terms of the new contracts are detailed in the table below.

At December 31, 2006, the fair value of the outstanding contracts was a net asset of approximately $5.2 million (See *ITEM 7. "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS* – RISK MANAGEMENT ACTIVITIES – DERIVATIVES AND HEDGING*")*. 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 hedge to increase or decrease by approximately $0.6 million.

Derivative contracts entered into after December 31, 2006 were as follows:

Transaction Date	Transaction Type (1)		Effective Dates Beginning	Effective Dates Ending	Price Per Unit	Volume Per Day
01/07	Natural Gas Collar		01/01/08	12/31/08	$7.50-$9.00	10,000 MMbtu
01/07	Natural Gas Collar		01/01/08	12/31/08	$7.50-$9.02	10,000 MMBtu
01/07	Natural Gas Collar	(2)	02/01/07	12/31/07	$7.02-$9.00	15,000 MMBtu
01/07	Natural Gas Collar	(2)	02/01/07	12/31/07	$7.00-$9.00	15,000 MMBtu
01/07	Natural Gas Collar		02/01/07	12/31/07	$7.00-$9.00	10,000 MMbtu
01/07	Natural Gas Collar		01/01/08	12/31/08	$7.50-$9.00	20,000 MMBtu

(1) Our January 2007 natural gas collars were entered into on a per MMbtu delivered price basis, using the NYMEX Natural Gas Index. Mark-to-market accounting treatment will be applied to these contracts and the change in fair value will be reflected in total revenue.

(2) These natural gas collars replaced contracts that were cancelled subsequent to December 31, 2006.

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

(a) Disclosure 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 ("SEC") under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

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 ("CEO") and Chief Financial Officer ("CFO"), of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. As described below under Management's Annual Report on Internal Control over Financial Reporting, our CEO and CFO have concluded that, as of the end of the period covered by this Annual Report on Form 10-K, the Company's disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

BDO Seidman, LLP's audit report, dated March 9, 2007, expressed an unqualified opinion on our consolidated financial statements and its assessment of Management's Annual Report on Internal Control over Financial Reporting is included herein under paragraph (d).

(b) Management's Annual Report on Internal Control over Financial Reporting. Management, including the CEO and CFO, has the responsibility for establishing and maintaining adequate internal control over financial reporting, as defined in the Exchange Act, Rule 13a-15(f). Internal control over financial reporting is a process designed by, or under the supervision of, the Company's principal executive and principal financial officers, or persons performing similar functions and influenced by the Company's Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America ("GAAP"). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. In addition, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate or insufficient because of changes in operating conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A control deficiency exists when the design or operation of a control does not allow management or employees, in the ordinary course of performing their assigned functions, to prevent or detect misstatements on a timely basis. A significant deficiency is a control deficiency, or combination of control deficiencies, that adversely affects the Company's ability to initiate, authorize, record, process, or report external financial data reliably in accordance with GAAP, such that there is a more than remote likelihood that a misstatement of the Company's annual or interim financial statements that is more than inconsequential will not be prevented or detected. A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

Management assessed internal control over financial reporting of the Company and subsidiaries as of December 31, 2006. The Company's management conducted its assessment in accordance with the *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Management has concluded that the internal control over financial reporting was effective as of December 31, 2006.

BDO Seidman, LLP, the independent registered public accounting firm who also audited the Company's consolidated financial statements, has issued its own attestation report on management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2006, which is filed herewith.

(c) Changes in Internal Control Over Financial Reporting. There have not been any changes in the Company's internal control over financial reporting during the fiscal quarter ended December 31, 2006 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

(d) Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Edge Petroleum Corporation
Houston, Texas

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Edge Petroleum Corporation maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO criteria). Edge Petroleum Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, management's assessment that Edge Petroleum Corporation maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also in our opinion, Edge Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Edge Petroleum Corporation as of December 31, 2006 and 2005 and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2006 and our report dated March 9, 2007 expressed an unqualified opinion thereon.

/S/ BDO SEIDMAN, LLP

BDO Seidman, LLP
Houston, TX
March 9, 2007

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information regarding directors and executive officers required under *ITEM 10* will be contained within the definitive Proxy Statement for the Company's 2007 Annual Meeting of Shareholders (the "Proxy Statement") under the headings "Election of Directors," "Meetings and Committees of the Board" 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, 2006. Pursuant to Item 401(b) of Regulation S-K certain of the information required by this item with respect to our executive officers 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," "Compensation Committee Interlocks and Insider Participation," "Compensation Committee Report" and "2006 Director 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, AND DIRECTOR INDEPENDENCE

The information required by *ITEM 13* will be contained in the Proxy Statement under the heading "Transactions with Related Persons" 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 as of October 7, 2004 (Incorporated by reference from exhibit 2.1 to the Company's Current Report on Form 8-K filed October 12; 2004).

2.4 — Purchase and Sale Agreement, dated as of September 21, 2005 among Pearl Energy Partners, Ltd., and Cibola Exploration Partners, L.P., as Sellers; and Edge Petroleum Exploration Company as Buyer and Edge Petroleum Corporation as Guarantor (Incorporated by reference from exhibit 2.1 to the Company's Current Report on Form 8-K filed October 19, 2005).

2.5 — Stock Purchase Agreement by and among Jon L. Glass, Craig D. Pollard, Leigh T. Prieto, Yorktown Energy Partners V, L.P., Yorktown Energy Partners VI, L.P., Cinco Energy Corporation, and Edge Petroleum Exploration Company and Edge Petroleum Corporation, dated as of September 21, 2005 (Incorporated by reference from exhibit 2.5 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2005).

2.6 — Letter Agreement dated November 18, 2005 by and among Edge Petroleum Exploration Company, Cinco Energy Corporation and Sellers (Incorporated by reference from exhibit 2.02 to the Company's Current Report on Form 8-K filed December 6, 2005). Pursuant to Item 601(b)(2) of Regulation S-K, the Company had omitted certain Schedules to the Letter Agreement (all of which are listed therein) from this Exhibit 2.6. It hereby agrees to furnish a supplemental copy of any such omitted item to the SEC on its request.

3.1 — Restated Certificate of Incorporation of the Company effective January 27, 1997 (Incorporated by reference from exhibit 3.1 to the Company's Current Report on Form 8-K filed April 29, 2005).

3.2 — Certificate of Amendment to the Restated Certificate of Incorporation of the Company effective January 31, 1997 (Incorporated by reference from exhibit 3.2 to the Company's Current Report on Form 8-K filed April 29, 2005).

3.3 - Certificate of Amendment to the Restated Certificate of Incorporation of the Company effective April 27, 2005 (Incorporated by reference from exhibit 3.3 to the Company's Current Report on Form 8-K filed April 29, 2005).

3.4 — 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).

3.5 — 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).

3.6 — 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 — Agreement and Amendment No. 1 to Third Amended and Restated Credit Agreement dated May 31, 2005 among Edge Petroleum Corporation, Edge Petroleum Exploration Company, Edge Petroleum Operating Company, Inc., Miller Exploration Company and Miller Oil Corporation, as borrowers, the lenders thereto and Union Bank of California, N.A., a national banking association, as agent for the lenders (Incorporated by reference from Exhibit 4.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2005).

4.3 — Agreement and Amendment No. 2 to the Third Amended and Restated Credit Agreement dated November 30, 2005 among Edge Petroleum Corporation, Edge Petroleum Exploration Company, Edge Petroleum Operating Company, Inc., Miller Oil Corporation, Miller Exploration Company, and Cinco Energy Corporation, as borrowers, the lenders thereto and Union Bank of California, N.A., a national banking association, as Agent (Incorporated by reference from Exhibit 4.3 to the Company's Annual Report on Form 10-K for the year ended December 31, 2005 (File No. 000-22149)).

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)).

4.8 — Fourth Amended and Restated Credit Agreement dated January 31, 2007 by and among Edge Petroleum Corporation, as borrower, and Union Bank of California, N.A., as Administrative Agent and Issuing Lender, and the other lenders party thereto (Incorporated by reference from exhibit 4.1 to Edge's Current Report on Form 8-K filed on February 5, 2007).

†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— Amended and Restated Incentive Plan of Edge Petroleum Corporation as Amended and Restated Effective as of August 1, 2006 (Incorporated by reference from exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the six months ended June 30, 2006).

†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 therein (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 Certain Other Compensation of Executive Officers.

†10.14– Description of Annual Cash Bonus Program for Executive Officers (Incorporated by reference from Exhibit 10.2 to the Company's Current Report on Form 8-K filed March 12, 2007).

†10.15– New Base Salaries and Long-Term Incentive Awards for Certain Executive Officers (Incorporated by reference from exhibit 10.1 to the Company's Current Report on Form 8-K filed August 25, 2006).

10.16 —Purchase and Sale Agreement between Smith Production, Inc., as seller, and Edge Petroleum Exploration Company, as purchaser, dated November 16, 2006 (Incorporated by reference to exhibit 10.1 to Edge's Current Report on Form 8-K filed January 16, 2007).

10.17 — Purchase and Sale Agreement between Smith Production, Inc., as seller, and Edge Petroleum Exploration Company, as purchaser, dated November 16, 2006 (Incorporated by reference to exhibit 10.2 to Edge's Current Report on Form 8-K filed January 16, 2007).

10.18 —First Amendment of Purchase and Sale Agreement between Smith Production, Inc., as seller, and Edge Petroleum Exploration Company, as purchaser, dated December 15, 2006 (Incorporated by reference to exhibit 10.3 to Edge's Current Report on Form 8-K filed January 16, 2007).

10.19 —Second Amendment of Purchase and Sale Agreement between Smith Production, Inc., as seller, and Edge Petroleum Exploration Company, as purchaser, dated January 15, 2007 (Incorporated by reference to exhibit 10.1 to Edge's Current Report on Form 8-K filed January 19, 2007).

10.20 —First Amendment of Purchase and Sale Agreement between Smith Production, Inc., as seller, and Edge Petroleum Exploration Company, as purchaser, dated January 15, 2007 (Incorporated by reference to exhibit 10.2 to Edge's Current Report on Form 8-K filed January 19, 2007).

10.21 — Third Amendment of Purchase and Sale Agreement between Smith Production, Inc., as seller, and Edge Petroleum Exploration Company, as purchaser, dated January 31, 2007 (Incorporated by reference to exhibit 10.6 to Edge's Current Report on Form 8-K filed February 7, 2007).

10.22 — Certificate of Designations establishing the 5.75% Series A cumulative convertible perpetual preferred stock, dated January 27, 2007 (Incorporated by reference to exhibit 3.1 to Edge's Current Report on Form 8-K filed January 30, 2007).

10.23 — Purchase and Sale Agreement between Kerr-McGee Oil & Gas Onshore, L.P., as Seller, and Edge Petroleum Production Company, as Purchaser, and Edge Petroleum Corporation, as Additional Purchaser dated December 12, 2006 (Incorporated by reference from exhibit 2.1 to the Company's Current Report on Form 8-K filed December 18, 2006).

*12.1 —Statement of Computation of Ratio of Earnings to Fixed Charges.

*21.1— Subsidiaries of the Company.

*23.1— Consent of BDO Seidman, LLP.

23.2 — Consent of Ryder Scott Company (Incorporated by reference from exhibit 23.1 to the Company's Current Report on Form 8-K filed January 23, 2007).

23.3 — Consent of W. D. Von Gonten & Co. (Incorporated by reference from exhibit 23.2 to the Company's Current Report on Form 8-K filed January 23, 2007).

*23.4 — Consent of Ryder Scott Company.

*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, 2006 (Incorporated by reference from exhibit 99.1 to the Company's Current Report on Form 8-K filed January 23, 2007).

99.2— Summary of Reserve Report of W. D. Von Gonten & Co. Petroleum Engineers as of December 31, 2006 (Incorporated by reference from exhibit 99.2 to the Company's Current Report on Form 8-K filed January 23, 2007).

99.3— Oversight review letter of Ryder Scott Company Petroleum Engineers dated January 11, 2007 (Incorporated by reference from exhibit 99.2 to the Company's Current Report on Form 8-K filed January 16, 2007).

*99.4— Supplemental Summary of Reserve Report of Ryder Scott Company Petroleum Engineers as of December 31, 2006.

* Filed herewith.

† Denotes management or compensatory contract, arrangement or agreement, or a summary or description thereof.

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

By /S/ John W. Elias
John W. Elias
Chief Executive Officer and Chairman of the Board
Date: March 12, 2007

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.

By /S/ John W. Elias John W. Elias Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	Date: March 12, 2007
By /S/ Michael G. Long Michael G. Long Executive Vice President and Chief Financial Officer (Principal Financial and Principal Accounting Officer)	Date: March 12, 2007
By /S/ Thurmon M. Andress Thurmon Andress Director	Date: March 12, 2007
By /S/ Vincent S. Andrews Vincent Andrews Director	Date: March 12, 2007
By /S/ Jonathan Clarkson Jonathan Clarkson Director	Date: March 12, 2007
By /S/ Michael A. Creel Michael A. Creel Director	Date: March 12, 2007
By /S/ Stanley S. Raphael Stanley S. Raphael Director	Date: March 12, 2007
By /S/ John Sfondrini John Sfondrini Director	Date: March 12, 2007
By /S/ Robert W. Shower Robert W. Shower Director	Date: March 12, 2007
By /S/ David F. Work David F. Work Director	Date: March 12, 2007

EDGE PETROLEUM CORPORATION

Index to Consolidated Financial Statements and Supplementary Information

CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

All schedules are omitted, as the required information is either inapplicable or the information is presented in the Consolidated Financial Statements or related notes.

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, 2006 and 2005 and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2006. 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Edge Petroleum Corporation at December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2006 the Company adopted the provisions of Statement of Financial Accounting Standards No. 123(R), "Share-Based Payment".

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Edge Petroleum Corporation's internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 9, 2007 expressed an unqualified opinion thereon.

/S/ BDO SEIDMAN, LLP

BDO Seidman, LLP

Houston, Texas
March 9, 2007

EDGE PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2005
	(in thousands, except share data)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,081	$ 666
Accounts receivable, trade, net of allowance	17,738	24,980
Accounts receivable, joint interest owners and other, net of allowance	2,217	2,100
Deferred income taxes	--	2,518
Derivative financial instruments	5,945	--
Other current assets	3,959	6,437
Total current assets	31,940	36,701
PROPERTY AND EQUIPMENT, Net – full cost method of accounting for oil and natural gas properties (including unevaluated costs of $57.6 million and $36.9 million at December 31, 2006 and 2005, respectively)	289,457	306,456
OTHER ASSETS	260	223
TOTAL ASSETS	$ 321,657	$ 343,380
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable, trade	$ 3,953	$ 5,571
Accrued liabilities	16,638	17,894
Derivative financial instruments	--	2,479
Accrued interest payable	541	17
Deferred income taxes	433	--
Asset retirement obligation – current portion	213	203
Total current liabilities	21,778	26,164
ASSET RETIREMENT OBLIGATION – long-term portion	3,158	2,564
DERIVATIVE FINANCIAL INSTRUMENTS	758	--
DEFERRED TAX LIABILITY	10,911	37,897
LONG-TERM DEBT	129,000	85,000
Total liabilities	165,605	151,625
COMMITMENTS AND CONTINGENCIES (Note 13)		
STOCKHOLDERS' EQUITY		
Preferred stock, $0.01 par value; 5,000,000 shares authorized; none issued and outstanding	--	--
Common stock, $0.01 par value; 60,000,000 shares authorized; 17,442,229 and 17,216,776 shares issued and outstanding at December 31, 2006 and 2005, respectively	174	172
Additional paid-in capital	141,685	137,842
Retained earnings	14,193	55,454
Accumulated other comprehensive loss	--	(1,713)
Total stockholders' equity	156,052	191,755
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 321,657	$ 343,380

See accompanying notes to the consolidated financial statements.

EDGE PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2006	**2005**	**2004**
	(in thousands, except share data)		
OIL AND NATURAL GAS REVENUE:			
Oil and natural gas sales	$ 120,014	$ 123,450	$ 66,965
Gain (loss) on derivatives	9,730	(2,267)	(2,460)
Total revenue	129,744	121,183	64,505
OPERATING EXPENSES:			
Oil and natural gas operating expenses including production and ad valorem taxes	18,257	17,068	9,309
Depletion, depreciation, amortization and accretion	61,080	40,218	21,928
Impairment of oil and natural gas properties	96,942	--	--
Bad debt expense	--	65	--
General and administrative expenses	13,788	12,371	9,447
Total operating expenses	190,067	69,722	40,684
OPERATING INCOME (LOSS)	(60,323)	51,461	23,821
OTHER INCOME (EXPENSE):			
Interest expense, net of amounts capitalized	(2,500)	--	(331)
Amortization of deferred loan costs	(165)	(153)	(142)
Interest income	152	128	36
INCOME (LOSS) BEFORE INCOME TAXES	(62,836)	51,436	23,384
INCOME TAX (EXPENSE) BENEFIT	21,575	(18,078)	(8,255)
NET INCOME (LOSS)	$ (41,261)	$ 33,358	$ 15,129
BASIC EARNINGS (LOSS) PER SHARE	$ (2.38)	$ 1.95	$ 1.16
DILUTED EARNINGS (LOSS) PER SHARE	$ (2.38)	$ 1.87	$ 1.11
BASIC WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING	17,368	17,122	13,029
DILUTED WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING	17,368	17,815	13,648

See accompanying notes to the consolidated financial statements.

EDGE PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,					
	2006		2005		2004	
			(in thousands)			
NET INCOME (LOSS)	$	(41,261)	$	33,358	$	15,129
OTHER COMPREHENSIVE INCOME (LOSS), net of tax:						
Change in fair value of outstanding hedging and derivative instruments (1)		--		(3,761)		953
Reclassification of hedging and derivative losses (2)		1,713		799		660
Other comprehensive income (loss)		1,713		(2,962)		1,613
COMPREHENSIVE INCOME (LOSS)	$	(39,548)	$	30,396	$	16,742
(1) net of income taxes	$	--	$	(2,025)	$	513
(2) net of income taxes	$	922	$	430	$	355

See accompanying notes to the consolidated financial statements.

EDGE PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2006	**2005**	**2004**
		(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (41,261)	$ 33,358	$ 15,129
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Unrealized (gain) loss on the fair value of derivatives	(5,031)	(720)	565
Loss on property	--	2	--
Depletion, depreciation, amortization and accretion	61,080	40,218	21,928
Impairment of oil and natural gas properties	96,942	--	--
Amortization of deferred loan costs	165	153	142
Deferred tax provision	(21,575)	18,078	8,255
Non-cash share-based compensation cost	2,807	2,769	1,746
Bad debt expense	--	65	--
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable, trade	7,242	(9,770)	(3,180)
(Increase) decrease in accounts receivable, joint interest owners	(117)	3,746	(4,113)
Increase in other assets	(536)	(1,062)	(259)
Increase (decrease) in accounts payable, trade	(1,618)	2,052	1,408
Increase in accrued interest payable	524	17	--
Increase (decrease) in accrued liabilities	(1,213)	4,205	649
Net cash provided by operating activities	97,409	93,111	42,270
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(144,338)	(123,959)	(89,470)
Drilling advances	2,869	(4,286)	--
Proceeds from the sale of oil and natural gas properties	628	--	60
Acquisition of Cinco Energy Corporation, net of cash acquired	429	(39,035)	--
Net cash used in investing activities	(140,412)	(167,280)	(89,410)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings from long-term debt	62,000	81,000	27,000
Payments on long-term debt	(18,000)	(16,000)	(28,000)
Net proceeds from issuance of common stock	576	7,615	49,507
Deferred loan costs	(158)	(47)	(427)
Net cash provided by financing activities	44,418	72,568	48,080
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,415	(1,601)	940
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	666	2,267	1,327
CASH AND CASH EQUIVALENTS, END OF YEAR	$ 2,081	$ 666	$ 2,267

See accompanying notes to the consolidated financial statements.

EDGE PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
	Shares	Amount				
				(in thousands)		
BALANCE, DECEMBER 31, 2003	12,581	$ 126	$ 75,282	$ 6,967	$ (364)	$ 82,011
Issuance of common stock	3,955	39	49,579	--	--	49,618
Compensation cost – restricted stock	--	--	498	--	--	498
Compensation cost – repriced options	--	--	1,136	--	--	1,136
Tax benefit associated with exercise of non-qualified stock options	--	--	462	--	--	462
Change in valuation of hedging instruments	--	--	--	--	1,613	1,613
Net income	--	--	--	15,129	--	15,129
BALANCE, DECEMBER 31, 2004	16,536	165	126,957	22,096	1,249	150,467
Issuance of common stock	681	7	7,776	--	--	7,783
Compensation cost – restricted stock	--	--	974	--	--	974
Compensation cost – repriced options	--	--	1,628	--	--	1,628
Tax benefit associated with exercise of non-qualified stock options	--	--	507	--	--	507
Change in valuation of hedging instruments	--	--	--	--	(2,962)	(2,962)
Net income	--	--	--	33,358	--	33,358
BALANCE, DECEMBER 31, 2005	17,217	172	137,842	55,454	(1,713)	191,755
Issuance of common stock	225	2	1,404	--	--	1,406
Compensation cost – restricted stock	--	--	1,908	--	--	1,908
Compensation cost – stock option expense	--	--	69	--	--	69
Tax benefit associated with exercise of non-qualified stock options	--	--	462	--	--	462
Change in valuation of hedging instruments	--	--	--	--	1,713	1,713
Net loss	--	--	--	(41,261)	--	(41,261
BALANCE, DECEMBER 31, 2006	17,442	$ 174	$ 141,685	$ 14,193	$ --	$ 156,05

See accompanying notes to the 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% 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. In December 2004 and January 2005, the Company completed a public offering of common stock in which 4.0 million shares were issued in order to fund the asset acquisition from Contango Oil & Gas Company ("Contango"). In November 2005, the Company acquired 100% of the stock of Cinco Energy Corporation ("Cinco"), which continues as a wholly owned subsidiary named Edge Petroleum Production Company (see Note 6).

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, Arkansas, 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, Edge Petroleum Production Company (formerly Cinco Energy Corporation), Miller Oil Corporation, and Miller Exploration Company, which are 100% owned subsidiaries of the Company. All intercompany balances and transactions have been eliminated in consolidation.

Changes in Accounting Principles – Beginning January 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 123(R), *Share-Based Payment.* This statement requires the Company to record expense associated with the fair value of stock-based compensation. The Company elected to use the modified-prospective adoption method for the standard which is discussed in further detail below and in Note 17.

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 derivatives. 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, 2006 and 2005 approximates fair value because the interest rates are variable and reflective of market rates. Derivative 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 its ability to collect the receivables in full. Many of the Company's receivables are from joint interest owners on properties of which the Company is the operator. Thus, the Company may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Generally, the Company's crude oil and natural gas receivables are collected within two to three 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 (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 one to seven years.

Oil and Natural Gas Properties - The accounting for our business is subject to special accounting rules that are unique to the oil and gas industry. 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. The Company utilizes the full-cost method of accounting for oil and natural gas properties. 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 also capitalizes a portion of interest expense on borrowed funds.

In the measurement of impairment of proved oil and gas properties, the successful-efforts method of accounting follows the guidance provided in 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 the "ceiling test," whereby to the extent that such capitalized costs subject to amortization in the full cost pool (net of depletion, depreciation and amortization 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 adjusted for asset retirement obligations net of salvage value, such excess costs are charged to expense. Once incurred, an impairment of oil and natural gas properties is not reversible at a later date. A ceiling test impairment could result in a significant loss for a reporting period; however, future depletion expense would be correspondingly reduced. In accordance with SEC Staff Accounting Bulletin ("SAB") No. 103, *Update of Codification of Staff Accounting Bulletins*, derivative instruments qualifying as cash flow hedges are to be included in the computation of limitation on capitalized costs. During the first quarter of 2006, the Company discontinued the use of cash flow hedge accounting; therefore, the ceiling test at December 31, 2006 was not impacted by the value of our derivatives. At December 31, 2005 and 2004, the Company was applying cash flow hedge accounting to its natural gas derivatives, and the period-end price was between the cap and floor established by the Company's hedge contracts and thus no impact was included in the ceiling test calculation.

Impairment of oil and natural gas properties is assessed quarterly in conjunction with the Company's quarterly and annual SEC filings. The Company recorded a non-cash ceiling test impairment of oil and natural gas properties for the year ended December 31, 2006 of $96.9 million ($63.0 million net of tax). The impairment was recorded in the third quarter of 2006 and was primarily the result of a decline in natural gas prices at September 30, 2006. At December 31, 2005, the quoted market prices, adjusted for differentials, utilized in calculating the full-cost ceiling were $10.05 per MMBtu for natural gas and $61.04 per barrel for crude oil. Our impairment of $96.9 million at September 30, 2006 was calculated based upon prices of $4.18 per MMBtu for natural gas and $62.92 per barrel for crude oil. Subsequent to the end of the reporting period, quoted market prices for natural gas increased such that we believe we would have avoided a write-down if, as would have been allowed under applicable accounting guidelines, we had elected to use such subsequent prices in calculating the ceiling test at September 30, 2006. No ceiling test impairment was required during the comparable 2005 and 2004 period.

The Company capitalized $3.0 million, $2.6 million, and $2.2 million of general and administrative costs in 2006, 2005 and 2004, respectively. The Company also capitalizes a portion of interest expense on borrowed funds related to unproved oil and gas properties. The Company capitalized approximately $5.3 million, $1.9 million, and $0.7 million of interest costs in 2006, 2005 and 2004, 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 $57.6 million and $36.9 million at December 31, 2006 and 2005, 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 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. The depletion rates per Mcfe for the years ended December 31, 2006, 2005 and 2004 were $3.51, $2.43, and $1.78, respectively.

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.

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. See further discussion in 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 15).

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

The following is a reconciliation of the numerators and denominators of basic and diluted earnings per common share computations, in accordance with SFAS No. 128, for the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
	(in thousands, except per share amounts)		
Net income (loss)	$ (41,261)	$ 33,358	$ 15,129
Basic weighted average shares outstanding	17,368	17,122	13,029
Add: dilutive effect of employee stock options	--	498	477
Add: dilutive effect of restricted stock units	--	195	142
Diluted weighted-average common shares outstanding	17,368	17,815	13,648
Basic income (loss) per common share	$ (2.38)	$ 1.95	$ 1.16
Diluted income (loss) per common share	$ (2.38)	$ 1.87	$ 1.11

Due to the Company's net loss in 2006 our unvested restricted stock units and stock options (429,567 equivalent shares) were not included in computing diluted earnings per share because the effect was antidilutive. In computing earnings per share, no adjustments were made to reported net income (loss).

Share-Based Compensation – At December 31, 2006, the Company had a share-based employee compensation plan that included restricted stock units and stock options issued to employees and non-employee directors, as more fully described in Note 17. Stock options were last issued in April 2004. Prior to 2006, the Company accounted for share-based compensation using the intrinsic value recognition and measurement principles detailed in Accounting Principles Board ("APB") Opinion No. 25, *Accounting for Stock Issued to Employees* and related interpretations. Except for certain repriced options described below, no share-based compensation expense relating to stock option grants was reflected in the Company's consolidated statements of operations for any period presented prior to 2006, since all options granted under the plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The Company used the Black-Scholes option calculation model to calculate the disclosures required under SFAS No. 123, *Accounting for Stock Based Compensation*. In 1999, the Company repriced certain employee and director stock options. The Company accounted for these repriced stock options in accordance with Financial Accounting Standards Board ("FASB") Interpretation No. 44 ("FIN 44"), *Accounting for Certain Transactions involving Stock Based Compensation – An Interpretation of APB No. 25*, which prescribed the variable plan accounting treatment for repriced options. Under variable plan accounting, compensation expense is adjusted for increases or decreases in the fair market value of the Company's common stock to the extent that the market value exceeds the exercise price of the option until the options are exercised, forfeited, or expire unexercised. Beginning January 1, 2006, the Company adopted the provisions of SFAS No. 123(R), *Share-Based Payment*. This statement requires the Company to record expense associated with the fair value of share-based compensation. The Company elected to use the modified-prospective adoption method for the standard and has consequently recognized additional compensation expense of $68,937 in 2006. No further expense associated with stock options is expected to be recognized unless future awards are granted. The Company has recorded compensation expense associated with the issuance of restricted stock and restricted stock units since the plan was adopted in 1997 and stock or stock units were first granted. The Company recognizes costs associated with these grants based on the estimated fair value of the restricted stock units as determined at the time of grant.

The following table illustrates the effect on net income and earnings per share information if the Company had applied the fair value recognition provision of SFAS No. 123(R) to options and restricted stock units granted under our share-based compensation plans in 2005 and 2004. For the purposes of this pro forma disclosure, the value is estimated using a Black-Scholes option-pricing formula and expensed over the option's vesting periods.

	Year Ended December 31, 2005	Year Ended December 31, 2004
	(in thousands, except per share amounts)	
Net income:		
As reported	$ 33,358	$ 15,129
Add: share-based employee compensation reported in net income, net of taxes	1,691	1,062
Deduct: share-based employee compensation under the fair value method for all awards, net of taxes	(822)	(608)
Pro forma net income	$ 34,227	$ 15,583
Earnings per share:		
Basic - as reported	$ 1.95	$ 1.16
Basic – pro forma	2.00	1.20
Diluted – as reported	1.87	1.11
Diluted – pro forma	1.95	1.16

Derivatives and Hedging Activities - The Company accounts for its derivative contracts under the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (as amended). The statement 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. 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. During the first quarter of 2006, the Company determined that the cash flow hedge accounting treatment previously applied to its natural gas contracts should be discontinued due to projected changes in the 2006 physical production volumes hedged and to give the Company more flexibility in how it markets its physical production. In 2006, the Company applied mark-to-market accounting treatment to all outstanding derivative contracts. Therefore, the changes in fair value are not deferred through other comprehensive income, but rather recorded in revenue immediately as unrealized gains or losses. Going forward, the Company will continue to evaluate the terms of new contracts entered into to determine whether cash flow hedge accounting treatment or mark-to-market accounting treatment will be applied. In the past, the Company has used mark-to-market accounting treatment for its crude oil contracts and cash flow hedge accounting treatment for its natural gas contracts, therefore unrealized gains and losses on the change in fair value of natural gas contracts between periods may not be comparable (see Note 9).

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 on the face of the consolidated statements of comprehensive income. For the years ended December 31, 2005 and 2004, the only component of other comprehensive income was changes in fair value of hedging instruments and reclassifications of hedging gains and losses. This component of other comprehensive income is not applicable in 2006 because cash flow hedge accounting was discontinued in the first quarter of the year.

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 $0.5 million related to non-payments from two purchasers of the Company's oil and natural gas, which remains in the allowance for doubtful accounts receivable, trade until such time as the Company discontinues pursuing recovery efforts. In 2006, the Company wrote off $1,571 in accounts receivable from joint interest owners. During 2005 the Company recorded $65,157 of bad debt expense to increase its allowance for outstanding receivables from joint interest owners and wrote off $142,386 in accounts receivable from joint interest owners. No bad debt expense was recorded in 2004 related to joint interest owners. The Company cannot ensure that similar such losses may not be realized in the future.

Recently Issued Accounting Pronouncements – In March 2006, the FASB issued SFAS No. 156, *Accounting for Servicing of Financial Assets*, which requires all separately recognized servicing assets and servicing liabilities be initially measured at fair value. SFAS No. 156 permits, but does not require, the subsequent measurement of servicing assets and servicing liabilities at fair value. Adoption is required as of the beginning of the first fiscal year that begins after September 15, 2006. Early adoption is permitted. The adoption of SFAS No. 156 is not expected to have a material effect on our consolidated financial position, results of operations or cash flows.

In June 2006, the FASB issued FIN 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109*, which clarifies the accounting for uncertainty in income taxes recognized in accordance with SFAS No. 109, *Accounting for Income Taxes*. FIN 48 prescribes a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, no benefit will be recorded. FIN 48 also requires that the amount of interest expense to be recognized related to uncertain tax positions be computed by applying the applicable statutory rate of interest to the difference between the tax position recognized in accordance with FIN 48 and the amount previously taken or expected to be taken in a tax return. The change in net assets as a result of applying this pronouncement will be considered a change in accounting principle with the cumulative effect of the change treated as an offsetting adjustment to the opening balance of retained earnings or goodwill, if allowed under existing accounting standards, in the period of transition. FIN 48 is effective as of January 1, 2007 and the Company is currently evaluating the effects, if any, that FIN 48 will have on its financial statements.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which provides guidance for using fair value to measure assets and liabilities. The standard also gives expanded information about the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect of fair value measurements on earnings. SFAS No. 157 does not expand the use of fair value in any new circumstances. SFAS No. 157 establishes a fair value hierarchy that prioritizes the information used to develop fair value assumptions. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. Early adoption is encouraged. The Company is currently assessing the impact, if any, that SFAS No. 157 will have on its financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, which permits entities to choose to measure many financial instruments and certain other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 applies to all entities and is effective for fiscal years beginning after November 15, 2007. The Company is currently determining the impact, if any, that SFAS No. 159 will have on its financial statements.

Reclassifications - Certain reclassifications of prior period balances 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, 2006 and 2005:

	December 31, 2006	December 31, 2005
	(in thousands)	
Joint interest owners	$ 2,218	$ 1,212
Chapman Ranch Field Asset Acquisition Purchase Price Adjustment (1)	--	818
Other Receivables (2)	2	75
Allowance for Doubtful Accounts Receivable (joint interest owners)	(3)	(5)
Net Accounts Receivable, joint interest owners and other	$ 2,217	$ 2,100

(1) This amount represents the accrual of revenues, net of expenses for the results of operations between September 1, 2005 and October 13, 2005 of the Chapman Ranch Field acquired properties, pursuant to closing provisions of the purchase and sale agreement for the Chapman Ranch Field asset acquisition in 2005 (see Note 6).

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

The following table sets forth changes in the Company's allowance for doubtful accounts receivable, trade and joint interest owners and other, for the years ended December 31, 2006, 2005 and 2004:

	Balance at Beginning of Year	Charged to Costs and Expenses	Deductions and Other	Balance at End of Year
		(in thousands)		
Year ended December 31, 2006:				
Allowance for doubtful accounts	$ 530	$ --	$ (2)	$ 528
Year ended December 31, 2005:				
Allowance for doubtful accounts	$ 607	$ 65	$ (142)	$ 530
Year ended December 31, 2004:				
Allowance for doubtful accounts	$ 607	$ --	$ --	$ 607

4. OTHER CURRENT ASSETS

Below are the components of other current assets as of December 31, 2006 and 2005:

	December 31, 2006	December 31, 2005
	(in thousands)	
Prepaid insurance	$ 397	$ 388
Prepayments and deposits to vendors	387	323
Prepaid seismic licenses	266	--
Drilling advances	1,151	4,286
Inventory (1)	1,758	1,440
Total other current assets	$ 3,959	$ 6,437

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

5. PROPERTY AND EQUIPMENT

At December 31, 2006 and 2005, property and equipment consisted of the following:

	December 31, 2006	December 31, 2005
	(in thousands)	
Developed oil and natural gas properties	$ 521,713	$ 401,697
Unevaluated oil and natural gas properties	57,577	36,949
Computer equipment and software	4,602	4,491
Other office property and equipment	2,588	2,515
Total property and equipment	586,480	445,652
Accumulated depletion, depreciation and amortization	(297,023)	(139,196)
Total property and equipment, net	$ 289,457	$ 306,456

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

	December 31, 2006	December 31, 2005
Year cost incurred:	*(in thousands)*	
1999	$ 193	$ 193
2000	--	--
2001	22	22
2002	88	88
2003	118	248
2004	228	3,510
2005	26,150	32,888
2006	30,778	--
Total	$ 57,577	$ 36,949

6. ACQUISITIONS AND DIVESTITURES

Chapman Ranch Field Acquisition in 2006 - On December 12, 2006, the Company executed an agreement to acquire certain working interests in the Chapman Ranch Field in Nueces County, Texas from Kerr-McGee Oil & Gas Onshore LP ("Kerr-McGee"), a wholly owned subsidiary of Anadarko Petroleum Corporation. In late 2005, the Company acquired non-operated working interests in certain wells in this field, as discussed below. Upon the closing of the Kerr-McGee acquisition on December 28, 2006, the Company assumed operatorship of Chapman Ranch. The base purchase price of the acquisition was $26.0 million. The purchase price was preliminarily adjusted at closing to $25.0 million (including a previously paid deposit of $2.6 million) as a result of adjustments to the purchase price for the results of operations between the December 1, 2006 effective date and the December 28, 2006 closing date, and other purchase price adjustments. There may be post-closing adjustments to the purchase price for results of operations between the effective date and closing date as further information becomes available. The Company financed the purchase price of the Kerr-McGee acquisition through $24.0 million in borrowings under its Credit Facility, the borrowing base of which was increased as a result of this transaction.

Chapman Ranch Field Acquisitions in 2005 - On September 21, 2005, the Company executed two separate and definitive agreements for the acquisition of (i) the stock of a private company, Cinco Energy Corporation ("Cinco"), whose primary asset is ownership of working interests in oil and natural gas properties located on the Chapman Ranch Field in Nueces County, Texas and (ii) additional working interests in the Chapman Ranch Field owned by two other private companies for an aggregate final purchase price of approximately $74.9 million (of which $46.9 million was attributable to the stock purchase and $28.0 million was attributable to the working interest asset purchase). The Company allocated approximately $17.5 million of the total purchase price to the unproved property category. Both purchase prices were subject to adjustment pursuant to the provisions of the applicable agreements. The Company also agreed to pay the sellers an aggregate incremental purchase price of $5.2 million (of which $3.0 million was attributable to the stock purchase and $2.2 million was attributable to the working interest asset purchase) related to the operator obtaining high-cost gas certification on or before January 31, 2006, which would provide for severance tax abatements on the properties acquired. The operator of the properties filed for the abatements and the Company was notified that not all of the properties qualified for high-cost gas certification, therefore the incremental purchase price was reduced to $4.8 million in January 2006. On November 30, 2005, the Company paid a portion of the incremental purchase price of $3.9 million when a portion of the properties qualified for the certification and incurred a contingent liability for the remaining balance of $0.9 million, which was paid to the Sellers in the first quarter of 2006. The Company financed the acquisitions through borrowings under its credit facility, the borrowing base of which increased in connection with these transactions and other recent activities since the last redetermination.

The asset purchase closed on October 13, 2005. The final purchase price of $28.0 million was adjusted for the incremental purchase price (see above) and the results of operations between the September 1, 2005 effective date and the October 13, 2005 closing date, pursuant to the closing adjustment provisions of the relevant agreement.

The stock purchase closed November 30, 2005. The final purchase price of $46.9 million was subject to adjustment for, among other things, working capital as of September 1, 2005 and an incremental purchase price (see above), pursuant to the closing provisions of the relevant agreement.

Pursuant to the terms of the stock purchase agreement, Cinco changed its name to Edge Petroleum Production Company. It will remain a wholly owned subsidiary of the Company going forward.

The Cinco acquisition was accounted for as a purchase business combination. Under this method of accounting, on the closing date, the assets and liabilities of Cinco were recorded by Edge at their estimated fair market values. The following allocation of the final purchase price to specific assets and liabilities has been adjusted for actual amounts.

In thousands:		
Cash	$	8,305
Current assets		2,470
Properties and equipment		53,065
Deferred tax liability (1)		(14,945)
Current liabilities		(1,919)
Asset retirement obligation		(64)
Stockholders' equity	$	46,912

(1) Represents certain tax liabilities resulting from the fair value and tax basis difference.

The following unaudited pro forma results for 2005 show the effect on the Company's consolidated results of operations as if the Cinco transaction had occurred on January 1, 2005. The following 2005 unaudited pro forma results are the result of combining the statement of operations of Edge with the statement of income for Cinco, adjusted for (i) assumption of ARO liabilities and accretion expense for the properties acquired, (ii) depletion, depreciation and amortization expense applied to the adjusted basis of the properties acquired using the purchase method of accounting, (iii) conversion of Cinco from successful efforts method of accounting to the full cost method of accounting, and (iv) the related income tax effects of these adjustments based on the applicable statutory rates. The pro forma information is based upon numerous assumptions, and is not necessarily indicative of future results of operations.

	For the Year Ended December 31, 2005	
	(unaudited) *(in thousands, except share data)*	
Revenue	$	131,289
Net income	$	27,202
Net income per common share:		
Basic	$	1.59
Diluted	$	1.53

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 final purchase price for the acquisition was $40.1 million, which was adjusted for the results of operations between the July 1, 2004 effective date and the December 29, 2004 closing date, pursuant to the closing adjustment provisions. The purchase price was funded from the net proceeds of a public offering of common stock completed on December 21, 2004 (see Note 11).

Divestitures - In 2006, the Company consummated the divestiture of its Buckeye properties located in Live Oak County, Texas for net proceeds of $627,645. During 2005, the Company had no divestitures of oil and gas properties. During 2004, the Company sold oil and gas properties for net proceeds of $60,000. The Company's 2004 asset divestitures related primarily to the sale of certain oil and gas properties and equipment in Texas, Mississippi and Louisiana. Proceeds from these dispositions were credited to the full-cost pool.

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, whereby the Company records an abandonment liability associated with its oil and natural gas wells when those assets are placed in service. The changes to the ARO during the periods ended December 31, 2006 and 2005 are as follows:

	For the Year Ended December 31,	
	2006	2005
	(in thousands)	
ARO, beginning of year	$ 2,767	$ 2,189
Additional liabilities incurred	572	588
Liabilities settled	(199)	(151)
Accretion expense	189	141
Revisions	42	--
ARO, end of year	$ 3,371	$ 2,767
Current portion	$ 213	$ 203
Long-term portion	$ 3,158	$ 2,564

ARO liabilities incurred during the year ended December 31, 2006 include obligations assumed for 39 wells that were successfully drilled during the year, several non-operated wells that were not previously identified and adjustments for additional working interests acquired in 19 wells in the Chapman Ranch Field. Liabilities settled during the year ended December 31, 2006 included 30 wells that were either plugged or sold.

8. ACCRUED LIABILITIES

Below are the components of accrued liabilities as of December 31, 2006 and 2005:

	As of December 31,	
	2006	2005
	(in thousands)	
Accrued capital expenditures	$ 6,603	$ 9,428
Professional services	1,244	850
Salaries and benefits	931	1,600
Royalties payable	4,014	4,133
Lease operating expenses including ad valorem taxes payable	2,438	1,409
Litigation settlement	1,328	--
Other	80	474
Total accrued liabilities	$ 16,638	$ 17,894

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 revenue, as well as to reduce exposure from price fluctuations. While the use of these arrangements may limit 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 and provide only partial price protection against declines in oil and natural gas 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* (as amended). 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 and the cash flows resulting from settlement of these derivative transactions are classified in operating activities on the statement of cash flows. For those derivatives in which mark-to-market accounting treatment is applied, the changes in fair value are not deferred through other comprehensive income on the balance sheet. Rather they are immediately recorded in total revenue on the statement of operations. For those derivative instrument contracts that are designed and 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 on the balance sheet and the ineffective portion of the changes in the fair value of the contracts is recorded in total revenue on the statement of operations, in either case, as such changes occur. When the hedged production is sold, the realized gains and losses on the contracts are removed from other comprehensive income and recorded in revenue. 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.

During the first quarter of 2006, the Company determined that the cash flow hedge accounting treatment previously applied to its natural gas contracts should be discontinued due to projected changes in the 2006 physical production volumes hedged and to give the Company more flexibility in how it markets its physical production. In 2006, the Company has applied mark-to-market accounting treatment to all outstanding derivative contracts, therefore the changes in fair value are not deferred through other comprehensive income, but rather recorded in revenue immediately as unrealized gains or losses. Going forward, the Company will continue to evaluate the terms of new contracts entered into to determine whether cash flow hedge accounting treatment or mark-to-market accounting treatment will be applied. In the past, the Company has used mark-to-market accounting treatment for its crude oil contracts and cash flow hedge accounting treatment for its natural gas contracts. Therefore, unrealized gains and losses on the change in fair value of natural gas contracts between periods may not be comparable.

For the years ended December 31, 2006, 2005 and 2004, the Company included in revenue realized and unrealized losses related to its derivative contracts. There was no ineffectiveness recognized during the years ended December 31, 2005 and 2004 when cash flow hedge accounting was applied to the Company's natural gas contracts. For the three years ended December 31, 2006, 2005 and 2004, the Company included in total revenue the following realized and unrealized gains and losses:

	For the Year Ended December 31,		
	2006	**2005**	**2004**
		(in thousands)	
Natural gas collar realized settlements	$ 4,699	$ (1,230)	$ (328)
Crude oil collar realized settlements	--	(1,757)	(881)
Hedge premium reclassification	--	--	(686)
Natural gas collar unrealized change in fair value	4,686	--	--
Crude oil collar unrealized change in fair value	345	720	(565)
Gain (loss) on hedging and derivatives	$ 9,730	$ (2,267)	$ (2,460)

The fair value of outstanding hedge and derivative contracts at December 31, 2006 and 2005 reflected on 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, 2006	2005
						(in thousands)	
Natural Gas (1):							
08/05	Natural Gas Collar	01/01/2006	12/31/2006	$7.00-$10.50	10,000MMbtu	$ --	$ (2,498)
08/05	Natural Gas Collar	01/01/2006	12/31/2006	$7.00-$16.10	10,000MMbtu	--	(137)
08/06	Natural Gas Collar (3)	01/01/2007	12/31/2007	$7.50-$11.50	5,000 MMbtu	2,301	--
08/06	Natural Gas Collar (3)	01/01/2007	12/31/2007	$7.50-$12.00	5,000 MMbtu	2,385	--
Crude Oil (2):							
08/05	Crude Oil Collar	01/01/2006	12/31/2006	$55.00-$80.00	400Bbl	--	156
08/06	Crude Oil Collar	01/01/2007	12/31/2007	$70.00-$87.50	400 Bbl	1,047	--
12/06	Crude Oil Swap	01/01/2007	12/31/2007	$66.00	600 Bbl	212	--
12/06	Crude Oil Swap	01/01/2008	12/31/2008	$66.00	1,500 Bbl	(758)	--
						$ 5,187	$ (2,479)

(1) The Company's current natural gas collars were entered into on a per MMbtu delivered price basis, using the Houston Ship Channel Index. Cash flow hedge accounting, which was applied to these contracts in 2005, was discontinued in 2006. During 2006, mark-to-market accounting treatment was applied to these contracts and the change in fair value is reflected in total revenue during the year.

(2) Cash flow hedge accounting is not applied to the Company's crude oil contracts, which were entered into on a per barrel delivered price basis, using the West Texas Intermediate Light Sweet Crude Oil Index, with settlement for each calendar month occurring five business days following the expiration date. Mark-to-market accounting treatment is applied to these contracts and the change in fair value is reflected in total revenue during the year.

(3) Subsequent to December 31, 2006, two natural gas collars covering a portion of our 2007 estimated production were terminated and replaced with new collars. The terms of the new contracts are detailed in the table below.

Derivative contracts entered into after December 31, 2006 were as follows:

Transaction Date	Transaction Type (1)	Effective Dates Beginning	Ending	Price Per Unit	Volume Per Day
01/07	Natural Gas Collar	01/01/08	12/31/08	$7.50-$9.00	10,000 MMbtu
01/07	Natural Gas Collar	01/01/08	12/31/08	$7.50-$9.02	10,000 MMbtu
01/07	Natural Gas Collar (2)	02/01/07	12/31/07	$7.02-$9.00	15,000 MMbtu
01/07	Natural Gas Collar (2)	02/01/07	12/31/07	$7.00-$9.00	15,000 MMbtu
01/07	Natural Gas Collar	02/01/07	12/31/07	$7.00-$9.00	10,000 MMbtu
01/07	Natural Gas Collar	01/01/08	12/31/08	$7.50-$9.00	20,000 MMbtu

(1) The Company's January 2007 natural gas collars were entered into on a per MMbtu delivered price basis, using the NYMEX Natural Gas Index, with settlement for each calendar month occurring five business days following the expiration date. Mark-to-market accounting treatment will be applied to these contracts and the change in fair value will be reflected in total revenue.

(2) These natural gas collars replaced contracts that were cancelled subsequent to December 31, 2006.

10. LONG-TERM DEBT

On December 21, 2006, the Company amended its Third Amended and Restated Credit Agreement (the "Prior Credit Facility"), which it had originally entered into in March 2004 (effective December 31, 2003) and previously amended on December 4, 2006. The Prior Credit Facility permitted borrowings up to the lesser of (i) the borrowing base and (ii) $150.0 million. Effective December 21, 2006, the Prior Credit Facility's borrowing base was increased from $125.0 million to $140.0 million. The borrowing base under the Prior Credit Facility was increased as a result of the Kerr-McGee acquisition and the Company's drilling activities since the last redetermination. The Company's available borrowing capacity under this facility was $11.0 million at December 31, 2006.

The Prior Credit Facility was scheduled to mature on March 31, 2008 and was secured by substantially all of the Company's assets. Borrowings under the Prior Credit Facility bore interest at rates that were variable based on percentage usage of the facility. Borrowings could be at Prime plus a margin of 0% to 0.25% or at LIBOR plus a margin of 1.75% to 2.125%. Outstanding availability bore interest rates of 0.25% to 0.50% based on utilization levels. At December 31, 2006 the interest rates applied to the Company's outstanding Prime and LIBOR borrowings were 8.500% and 7.485%, respectively. As of December 31, 2006, $129.0 million in borrowings were outstanding under the Prior Credit Facility.

The Prior Credit Facility provided 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 Prior Credit Facility also prohibited dividends on our common stock and certain distributions of cash or properties and certain liens. The Prior Credit Facility also contained the following financial covenants, among others:

- The EBITDAX to Interest Expense ratio required 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 required that the amount of the Company's consolidated current assets less its consolidated current liabilities, as defined in the Credit Facility Agreement, be at least $1.0 million. For the purposes of calculating the Working Capital ratio, the total of current assets was adjusted for unused capacity under the Credit Facility Agreement, and derivative financial instruments and the total of current liabilities is adjusted for derivative financial instruments and asset retirement obligations.
- The Maximum Leverage ratio required that the ratio, as of the last day of any fiscal quarter, of (a) Total Indebtedness (as defined in the Credit Facility Agreement) 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 lenders and is defined above as part of the Company's disclosure of its covenant obligations.

11. SHELF REGISTRATION STATEMENT

During the second quarter 2005, the Company filed a registration statement with the SEC which registered offerings up to $390 million of any combination of debt securities, preferred stock, common stock or warrants for debt securities or equity securities of the Company. 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 the shelf registration statement for the purpose of issuing, from time to time, any combination of debt securities, preferred stock, common stock or warrants 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.

On December 21, 2004, the Company completed an offering of 3.5 million shares of its common stock, which generated net proceeds of $47.8 million, before direct costs of the offering of $0.6 million. These funds were used to finance the south Texas asset acquisition that closed December 29, 2004 and fund other general corporate purposes. On January 5, 2005, the underwriters exercised their over-allotment option for an additional 0.5 million shares of common stock, which generated additional net proceeds of $7.2 million. These funds were used to reduce outstanding debt. Each of these sales was made under the Company's initial shelf registration statement. At December 31, 2006, the Company had $390 million available for issuance under its 2005 shelf registration statement.

In January 2007, the Company completed an offering of 10.925 million shares of its common stock and 2.875 million shares of 5.75% Series A cumulative convertible perpetual preferred stock, as discussed further below in

Note 12. As a result of the offerings, the Company had approximately $101.5 million remaining available under its 2005 shelf registration statement.

12. SUBSEQUENT EVENTS

Acquisitions - On November 16, 2006, the Company entered into two separate purchase and sale agreements (one of which was subsequently amended) with Smith Production Inc. ("Smith") for (A) (i) ownership interests in certain oil and gas properties located in 13 counties in southeast and south Texas, consisting of approximately 150 gross (74 net) producing wells from Smith and eight other owners who transferred their interests to Smith prior to the closing, (ii) an ownership interest in approximately 17,000 gross (12,250 net) developed acres and 56,000 gross (16,000 net) undeveloped acres of leasehold, (iii) 25% of Smith's option and leasehold rights and exploration and development rights in an approximate 95 square mile exploration project area known as the Mission project area, also in south Texas, and (iv) certain gathering facilities and ownership to approximately 13 miles of natural gas gathering pipelines and related infrastructure serving producing assets in southeast Texas ((i) through (iv) collectively referred to as the "Smith Properties"); and (B) working interest, option and leasehold rights in two exploration ventures in separate areas, primarily in Texas, from Smith (the "Smith Ventures" and collectively with the Smith Properties, the "Properties"). The combined cash purchase price paid at closing on January 31, 2007 was approximately $379.8 million for the Smith Properties and $10.0 million for the Smith Ventures. The purchase price for the Smith Properties was adjusted from the base purchase price of $385 million for, among other things, the results of operations of the Smith Properties between the January 1, 2007 effective date and the January 31, 2007 closing date. The Company expects further adjustments to the purchase price pursuant to the post-closing adjustment provisions of the amended purchase and sale agreements.

Public Offerings - In order to finance a portion of the Smith acquisition, on January 30, 2007, the Company completed an offering of 10.925 million shares of its common stock, as well as an offering of 2.875 million shares of 5.75% Series A cumulative convertible perpetual preferred stock. The shares were offered to the public at a price of $13.25 per share of common stock and $50.00 per share of preferred stock. The Company received net proceeds of approximately $276.7 million, before other direct costs, from the offerings ($138.1 million from the common offering and $138.6 from the preferred offering), after deducting underwriting discounts and commissions and the estimated expenses of the offerings. As a result of the offerings, the Company had approximately $101.5 million remaining available under its 2005 shelf registration statement as of March 9, 2007.

Credit Facility - On January 30, 2007, the Company entered into a Fourth Amended and Restated Credit Agreement for a new Revolving Credit Facility with Union Bank of California ("UBOC") and the other lenders party thereto. Pursuant to the agreement, UBOC will act as the administrative agent for a senior, first lien secured borrowing base revolving credit facility (the "Credit Facility") for the Company in an amount equal to $750 million, of which $320 million was initially made available under the borrowing base established at the closing. The Credit Facility has a letter of credit sub-limit of $20 million. In connection with the Credit Facility, the Company paid the lenders fees in an amount equal to 1.00% of the initial borrowing base established under the Credit Facility, or $3.2 million, on January 31, 2007. The Company paid approximately $0.4 million to the lenders for certain other administrative fees, fronting fees and work fees in connection with the Credit Facility.

The Credit Facility matures on January 31, 2011 and is secured by substantially all of the Company's assets. Borrowings under the Credit Facility bear interest at LIBOR plus an applicable margin ranging from 1.25% to 2.5%, with an unused commitment fee ranging from 0.50% to 0.25%.

The Credit Facility provides for certain restrictions and covenants, 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 restricts dividends and certain distributions of cash or properties and certain liens and also contains financial covenants including, without limitation, the following:

- An EBITDAX to interest expense ratio requires that as of the last day of each fiscal quarter the ratio of (a) the Company's consolidated EBITDAX (defined as EBITDA plus similar non-cash items and exploration and abandonment expenses for such period) to (b) the Company's consolidated interest expense, not be less than 2.5 to 1.0, calculated on a cumulative quarterly basis for the first 12 months after the closing of the Credit Facility and then on a rolling four quarter basis.

- A current ratio requires that as of the last day of each fiscal quarter the ratio of the Company's consolidated current assets to the Company's consolidated current liabilities, as defined in the Credit Facility, be at least 1.0 to 1.0.

- A maximum leverage ratio requires that as of the last day of each fiscal quarter the ratio of (a) Total Indebtedness (as defined in the Credit Facility) to (b) an amount equal to consolidated EBITDAX be not greater than 3.0 to 1.0, calculated on a cumulative quarterly basis for the first 12 months after the closing of the Credit Facility and then on a rolling four quarter basis.

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

UBOC had previously provided the Company a commitment letter for a $250 million senior, second lien secured bridge loan facility (the "Bridge Loan Facility"). The Bridge Loan Facility, along with the Credit Facility, was intended to replace the Company's existing credit facility and to fund the Smith acquisition described above if the Company was unable to complete one or both of its previously announced public offerings. Due to the successful completion of the Company's public offerings of common stock and Series A preferred stock on January 30, 2007, the Company did not enter into the Bridge Loan Facility. The Company paid an amount equal to 0.50% of the commitment under the Bridge Loan Facility, or $1.3 million, on January 31, 2007 which was recorded in the first quarter of 2007.

In connection with the Credit Facility, Edge terminated its existing Third Amended and Restated Credit Agreement, which it had originally entered into in March 2004 (effective December 31, 2003). The balance of the borrowings under this prior credit facility of $129.0 million was repaid on January 30, 2007 with the proceeds from the public offerings described above. As of March 9, 2007, the Company had borrowings of $235.0 million outstanding under its Credit Facility.

13. COMMITMENTS AND CONTINGENCIES

Commitments - At December 31, 2006, the Company was obligated under non-cancelable operating leases. Following is a schedule of the remaining future minimum lease payments under these leases:

		(in thousands)
2007	$	817
2008		826
2009		818
2010		816
2011		804
Remainder		1,273
Total	$	5,354

Rent expense for the years ended December 31, 2006, 2005 and 2004 was approximately $0.7 million, $0.7 million, and $0.5 million, 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 material adverse effect on the Company's financial condition, results of operations or cash flows except as set forth below.

Texas Comptroller Audit - During the second quarter of 2004, the Company received notice that a subsidiary's franchise tax returns for the State of Texas would be audited for the tax years 1999 through 2002. After reviewing the 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 Company to its subsidiary, which had been 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 2006, the Company and the Comptroller agreed upon a method of computing the Company's franchise tax liability to the State of Texas for tax years 1999 through 2002 that resulted in a total one-time payment of $144,474, plus penalties of $9,228, which was recorded in 2006. Interest on this settlement of $40,150 was paid in the fourth quarter of 2006.

Wade and Joyce Montet, et al., v. Edge Petroleum Corp of Texas, et al., consolidated with Rolland L. Broussard, et al., v. Edge Petroleum Corp of Texas, et al. - This is a consolidated suit, filed in state court in Vermilion Parish, Louisiana in September 2003. Plaintiffs are mineral/royalty owners under the Norcen-Broussard No. 1 and 2 wells, Marg Tex Reservoir C, Sand Unit A (Edge's old Bayou Vermilion Prospect). They claim the operator at the time, Norcen Explorer, now Anadarko, failed to "block squeeze" the sections of the No. 2 well, as a prudent operator, according to their allegations, would have done, to protect the gas reservoir from being flooded with water from adjacent underground formations. Plaintiffs further allege Norcen was negligent in not creating a field-wide unit to protect their interests. The allegations relate to actions taken beginning in the early 1990's. Plaintiffs have named the Company and other working interest owners in the leases as defendants, including Norcen Explorer's successors in interest, Anadarko. Plaintiffs originally sought unspecified damages for lost royalties and damages due to alleged devaluation of their mineral and property interests, plus interest and attorneys' fees. In early 2005, the Company filed a motion for summary judgment in the case asserting, among other defenses, that: (i) there has been no breach of contract, (ii) there is no express or implied duty imposed on us to block squeeze the well or form a field-wide unit, (iii) the units were properly formed by the Conservation Commissioner in accordance with the statutory scheme in Louisiana, (iv) plaintiffs' claims are barred by limitations, and (v) other defenses. Along with the other defendants, the Company also filed a special peremptory challenge of no cause of action under the leases and the Louisiana Mineral Code for failure to exhaust administrative remedies and due to lack of a demand. In May and June 2005, the court ruled against us on the motion for summary judgment and the peremptory challenges. Of the 18.75% after-payout working interest that was originally reserved in the leases, the Company owned a 2.8% working interest at the time of the alleged acts or omissions. On September 6, 2005, the Company filed a third-party demand to join the other working interest owners who hold the remainder of the 18.75% working interest as third-party defendants in this case. These third-parties consist, for the most part, of partnerships that are directly or indirectly controlled by John Sfondrini, a director of the Company, and hold an aggregate 14.7% working interest (the "Sfondrini Partnerships"). Vincent Andrews, also a director of the Company, owns a minority interest in the corporate general partner of one of the partnerships. The Sfondrini Partnerships consist of (1) Edge Group Partnership, a general partnership composed of limited partnerships of which Mr. Sfondrini and a company controlled by Mr. Sfondrini are general partners; (2) (A) Edge Option I Limited Partnership, (B) Edge Option II Limited Partnership and (C) Edge Option III Limited Partnership, limited partnerships of which Mr. Sfondrini and a company controlled by Mr. Sfondrini are general partners; and (3) BV Partners Limited Partnership, a limited partnership of which a company controlled by Messrs. Sfondrini and Andrews is general partner and of which Mr. Sfondrini is manager (and of which company Mr. Andrews is an officer). These partnerships were among the third party defendants that the Company has sought to join in the case, and these partnerships have for the most part filed answers denying any liability to the Company. The Company participated for its 2.8% share of the well costs and revenues for the Broussard No. 2 well, as did the other defendants for their share, including the third-party defendant partnerships who participated for 14.7%. The Company strongly believes the parties should only be liable for their proportionate share of any damages award should a finding of liability occur in the case. The Company intends to vigorously contest the plaintiffs' claims.

As of the date of this report, it is not possible to determine what, if any, the Company's ultimate exposure might be in this matter. Prior to the settlement described below, plaintiffs had asserted damages, including interest, to be as high as $63 million. The plaintiffs' expert witness, in his December 2005 deposition, offered his theory that plaintiffs' gross damages are in the range of $19 to $22 million. That number is based on his theory that the alleged failure to block squeeze the well resulted in the under-production of gas worth $300 million. Plaintiffs' royalty share of that figure yields the $19 to $22 million range of alleged damages. Based on the expert's testimony, damages attributable to the full 18.75% interest would be in the range of $3.75 million gross or net to our 2.8% share would be in the range of $560,000 (excluding interest and attorneys' fees). Along with the other defendants, the Company hired its own expert witnesses who have refuted these claims, particularly the expert's assertions that failure to block squeeze the well caused any damages to the reservoir. The deposition of a Norcen engineer who prepared the completion plan for the Broussard No. 2 well and supervised the completion operations, taken in April 2006, confirms the testimony of the defense experts as to why the well was not block squeezed. The plaintiffs have also retained a damages expert who has given a report that the damages in this case are in the range of $30 million, excluding interest and attorneys' fees. The Company's share of that amount based on the full 18.75% would be approximately $5.6 million and net to our 2.8% share would be approximately $840,000. The Company participated in mediation of this lawsuit on July 18, 2006 but the parties failed to reach an agreement. In July 2006, the plaintiffs' attorney sent a demand to the defendants for total damages claimed by plaintiffs, with legal interest, totaling $63 million. The Company's share of that amount based on the full 18.75% interest would be approximately $12.2 million and net to our 2.8% interest would be approximately $1.8 million. On July 31, 2006, the Judge granted the defendant groups' motion for partial summary judgment dismissing plaintiffs' tort-based claims. Also on the same date, the Judge granted the defendant groups' motion for partial summary judgment seeking to deny the plaintiffs an award of attorneys' fees and also to dismiss any claim of plaintiffs that defendants had an obligation to form a field-wide unit.

Broussard Plaintiff Settlement.

On December 19, 2006, the Company, along with the other defendants in this suit, reached a settlement agreement with the Broussard Plaintiffs in full settlement of their 72% of the total claims made in this consolidated action. This settlement was finalized in January 2007. The Company's share of this settlement totaled approximately $208,000, which was recorded in December 2006, and the Sfondrini Partnerships' share totaled $1,109,759. The settlement with the Broussard Plaintiffs was finalized on February 1, 2007, and the defendants and the third-party defendants including the Sfondrini Partnerships were released from all claims by the Broussard Plaintiffs.

The Sfondrini Partnerships did not have sufficient cash to fund their respective full portion of the settlement. Therefore, in order to facilitate the settlement, the Company purchased certain oil and gas properties from certain of the Sfondrini Partnerships, with the proceeds of such sale and purchase generally being directed to payment of the Broussard settlement, in full satisfaction of the Sfondrini Partnerships' share of such settlement. The oil and gas properties that the Company purchased from the Sfondrini Partnerships and their respective purchase prices are as follows:

(1) 100% of each of Edge Group Partnership's, Edge Option I Limited Partnership's, Edge Option II Limited Partnership's and Edge Option III Limited Partnership's interest in the Ilse Miller No. 2 Well and leases, Wharton County, Texas, for a total combined value of $51,243.

(2) 100% of each of Edge Group Partnership's, Edge Option I Limited Partnership's, Edge Option II Limited Partnership's and Edge Option III Limited Partnership's interest in the Wm Baas 2-16 No. 1 Well and leases, Monroe County, Alabama, for a total combined value of $14,407.

(3) 55.953% of Edge Group Partnership's interest in certain wells and leases in the Company's Austin and Nita prospects, for a total value of $1,044,109.

In the purchase and sale transaction between us and the Sfondrini Partnerships, BV Partners Limited Partnership, whose 2.48% share of the Broussard settlement amount was $186,000 (as determined by the Company and Mr. Sfondrini on behalf of the BV Partners Limited Partnership), did not sell any assets to the Company and did not have sufficient funds to satisfy their share of the settlement amount. In addition, the Edge Option I, II and III Limited Partnerships did not have sufficient assets to satisfy their respective .34%, .34% and 2.25% shares of the settlement amount, which the Company and Mr. Sfondrini determined to be $25,750, $25,750 and $169,102, respectively. The shortfall amounts of Edge Option I, II and III Limited Partnerships were, net of assets that they sold to the Company, determined by the Company and Mr. Sfondrini to be $24,333, $24,333 and $163,276, respectively. As a result, Edge Group Partnership sold additional properties (over the amount necessary to fund its portion of the settlement) to the Company at fair market value in an amount sufficient to allow it to have proceeds from such sale to fund BV Partners Limited Partnership's share of the settlement and the remaining shortfall amounts owed by Edge Option I, II and III. In return, BV Partners and Edge Option I, II and III contributed all of their interest in the Bayou Vermilion Prospect leases and the Trahan No. 3 well located thereon to Edge Group

Partnership. The fair market value of these interests contributed to Edge Group by BV Partners Limited Partnership and Edge Option I, II and III were determined by the Company and Mr. Sfondrini on behalf of such partnerships to be $27,793, $3,847, $3,847 and $25,263, respectively.

The valuations of the interests of the Sfondrini Partnerships purchased by the Company and the interests contributed to Edge Group Partnership by BV Partners and Edge Option I, II and III were made at an agreed value, using a PV10 model and assuming $7.50/MMBtu gas and $60/BBl oil, which the Company believed represented current pricing levels for oil and gas properties at the time, and were agreed to by the Company and Mr. Sfondrini, on behalf of the Sfondrini Partnerships.

The trial on the remaining claims, those of the Montet plaintiffs (approximately 28% of the original aggregate claims in the case), is now set for trial beginning August 27, 2007. The Montet plaintiffs' calculation of their alleged damages has not changed. If the jury were to adopt the plaintiffs' damage figures, the total damages attributable to the Montet plaintiffs could be approximately $17.6 million. The defendants' exposure for an 18.75% share of that number would be approximately $3.31 million. The exposure for the Company's 2.8% share would be approximately $493,000. If there were a damage award against the defendants, the Company believes that ultimately it should only be liable for its 2.8% share of any such award unless a co-party defendant, including any of the third-party defendants, cannot satisfy their share of any final judgment or settlement amount or are found not to be liable to the Company on its third-party demand. In that event, the Company could be held responsible for more than its 2.8% share. The Company believes it has meritorious defenses and intends to continue to vigorously contest this suit and its third-party demands against the partnerships. The Company has not established a reserve with respect to these claims.

The Company may have insurance coverage for all or part of this claim up to the policy limits of $1 million per occurrence and $2 million in the aggregate. A claim was submitted to Mid-Continent Casualty Company, our casualty carrier, who is currently providing a defense under a reservation of rights letter. However, on July 3, 2006, Mid-Continent filed a suit for declaratory judgment against us in federal district court in Houston, Texas seeking to determine whether it has a duty to indemnify the Company and certain other defendants for this loss under the policies at issue. Mid-Continent has asked the court to declare they have no obligation to indemnify the Company and the third-party defendants based on certain technical definitions under the policies and the fact that the plaintiffs' claims are based on alleged breaches of contract. The Company is both vigorously defending the declaratory judgment action, and actively seeking indemnity under the policies at issue for its potential liabilities, if any, to the plaintiffs in the Louisiana actions. The Company is also pursuing coverage claims under other insurance policies that could cover a portion of our share of a loss in this case.

David Blake, et al. v. Edge Petroleum Corporation – On September 19, 2005, David Blake and David Blake, Trustee of the David and Nita Blake 1992 Children's Trust filed suit against the Company in state district court in Goliad County, Texas alleging breach of contract for failure and refusal to transfer overriding royalty interests to plaintiffs in at least five leases in Goliad County, Texas and failure and refusal to pay monies to Blake pursuant to such overriding royalty interests for wells completed on the leases. The plaintiffs seek relief of (1) specific performance of the alleged agreement, including granting of overriding royalty interests by the Company to Blake; (2) monetary damages for failure to grant the overriding royalty interests; (3) exemplary damages for his claims of business disparagement and slander; (4) monetary damages for tortuous interference; and (5) attorneys' fees and court costs. Venue of the case was transferred to Harris County, Texas by agreement of the litigants. The Company has served plaintiffs with discovery and has filed a counterclaim and an amended counterclaim joining various related entities that are controlled by plaintiffs. In addition, plaintiffs have filed an amended complaint alleging claims of slander of title and tortuous interference related to its alleged right to receive an overriding royalty interest from a third party. Plaintiffs currently have on file an amended motion for summary judgment, to which the Company has filed a response. In addition, the Company has filed a motion for summary judgment on the plaintiffs' case. In December 2006, the court denied the Company's motion for summary judgment. The court has not ruled on Blake's motion. The trial setting in March 2007 has been postponed by agreement of the parties and reset to September 15, 2007. Discovery in the case has commenced and is continuing. The Company has responded aggressively to this lawsuit, and believes it has meritorious defenses and counterclaims.

14. SALES TO MAJOR CUSTOMERS AND OPERATORS

In accordance with 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, 2006, 2005, and 2004 as listed below:

Purchaser	For the Year Ended December 31, 2006	2005	2004
Kinder Morgan	37%	29%	*
Chevron Corporation	12%	18%	22%
Copano Field Services	10%	17%	19%
Kerr-McGee Oil & Gas	10%	*	*
Upstream Energy Services (1)	3%	5%	22%

* Zero or less than 1%.

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

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 derivative instruments.

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.

15. INCOME TAXES

Income tax expense, including deferred amounts, is summarized as follows:

	2006	2005 (in thousands)	2004
Current			
Federal	$ 51	$ 327	$ --
State	--	--	--
Total Current	51	327	--
Deferred			
Federal	(21,959)	17,751	8,255
State	333	--	--
Total Deferred	(21,626)	17,751	8,255
TOTAL	$ (21,575)	$ 18,078	$ 8,255

Total income taxes differed from the amounts computed by applying the statutory income tax rate to income before income taxes. The sources of these differences are as follows:

	2006	2005	2004
		(in thousands)	
Income (Loss) Before Income Taxes	$ (62,836)	$ 51,436	$ 23,384
Statutory tax rate	35%	35%	35%
Tax computed on statutory rate	$ (21,993)	$ 18,003	$ 8,184
Adjustments resulting from:			
State income taxes (net of federal income tax benefit)	333	--	--
Expenses not deductible for tax purposes and other	85	75	71
Total income tax expense (benefit)	$ (21,575)	$ 18,078	$ 8,255
Effective tax rate	34.3%	35.2%	35.3%

The effect of stock-based compensation expense for tax purposes in excess of amounts recognized for financial accounting purposes has been credited directly to stockholders' equity in the amounts of approximately $461,900, $507,300 and $462,000 for 2006, 2005 and 2004, respectively.

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. Under this method, future income tax assets and liabilities are determined based on the "temporary differences" between the accounting basis and the income tax basis of the Company's assets and liabilities measured using the currently enacted, or substantially enacted, income tax rates in effect when these differences are expected to reverse. Significant components of the Company's deferred tax liabilities and assets as of December 31, 2006 and 2005 are as follows:

	As of December 31,	
	2006	2005
	(in thousands)	
Deferred tax liability – current:		
Price-risk management liability	$ (1,816)	$ (252)
Deferred tax asset – current:		
Price-risk management	--	922
Compensation cost	894	1,076
Expenses not currently deductible for tax purposes	289	542
Other	200	230
Total deferred tax asset – current	1,383	2,770
Net deferred tax asset (liability) – current	$ (433)	$ 2,518
Deferred tax liability – long-term:		
Book basis of oil and natural gas properties in excess of tax basis	$ (37,807)	$ (58,247)
Deferred tax asset – long-term:		
Net operating loss carryforwards	25,956	19,532
Accretion on ARO	246	180
Federal alternative minimum tax credits	497	445
Other	197	193
Total deferred tax asset – long-term	26,896	20,350
Net deferred tax liability – long-term	$ (10,911)	$ (37,897)

Total deferred taxes at December 31, 2006 include state deferred taxes of approximately $333,000. No state deferred taxes were included at December 31, 2005.

Tax carryforwards at December 31, 2006, which are available for utilization on future income tax returns, are as follows:

	Domestic	Expiration
	(in thousands)	
Net operating loss – regular tax	$ 73,553	2012 - 2026
Net operating loss - state	$ 465	2007 - 2017

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.

16. 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, 2006, 2005 and 2004, the Company contributed approximately $480,300, $176,500, and $121,300, respectively, to the Plan. In 2006, the Company increased the percentage of employee contributions that it matches, which accounts for the significant increase between 2005 and 2006.

17. 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 3.5 million 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. In January 2005, the underwriters exercised their overallotment option for 0.5 million additional shares of common stock, resulting in an additional $7.2 million of net proceeds to the Company.

Share-Based Compensation – The Company established the Incentive Plan of Edge Petroleum Corporation (the "Incentive Plan") in conjunction with its initial public offering in March 1997. 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 to 4 years. The Company amended the Incentive Plan (i) in December 2003 to increase the shares available under the plan from 1.2 million shares to 1.7 million shares and (ii) in June 2006 to increase the number of shares available under the Plan from 1.7 million shares to 2.2 million shares. Of the aggregate 2.2 million shares of common stock reserved for grants under the Incentive Plan, 501,446 shares were available for future grants at December 31, 2006. The following nonqualified stock option awards and restricted stock unit grants were made under the Incentive Plan during each of the years indicated below:

	Number Granted	Market Value on Date of Grant
Options Awards:		
2006	--	--
2005	--	--
2004	13,000	$13.99
Restricted Stock Awards (1):		
2006	326,280	$16.42 to $32.40
2005	131,640	$14.02 to $25.12
2004	94,676	$10.09 to $16.89

(1) Restricted stock awards granted, as presented above, are net of shares forfeited or cancelled during the corresponding year.

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 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 ("APIC"). The amortization of compensation expense related to this award is included in general and administrative expenses on the consolidated statement of operations. Below is a summary of options and restricted stock grants made to Mr. Elias 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.

Effective January 1, 2006, the Company adopted SFAS No. 123(R) utilizing the modified prospective approach. Prior to the adoption of SFAS No. 123(R), the Company accounted for stock option grants in accordance with APB No. 25 using the intrinsic value method, and accordingly, recognized no compensation expense for stock option grants. In 1999, the Company repriced certain employee and director stock options. The Company accounted for these repriced stock options in accordance with FIN 44 which prescribed the variable plan accounting treatment for repriced options. Under variable plan accounting, compensation expense is adjusted for increases or decreases in the fair market value of the Company's common stock to the extent that the market value exceeds the exercise price of the option until the options are exercised, forfeited, or expire unexercised.

Under the modified prospective approach, SFAS No. 123(R) applies to new awards and to awards that were outstanding on January 1, 2006 that are subsequently modified, repurchased or cancelled. Under the modified prospective approach, compensation cost recognized in the first quarter of fiscal 2006 includes compensation cost for all share-based payments granted prior to, but not yet vested, as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123 and compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123(R). Prior periods were not restated to reflect the impact of adopting the new standard.

Share-based compensation costs for the years ended December 31, 2006, 2005 and 2004 were:

	Year Ended December 31,		
	2006 (1)	2005 (2)(3)	2004 (2)(3)
		(in thousands)	
Stock options	$ 69	$ --	$ --
Repriced stock options (2)	--	1,628	1,136
Restricted stock units	1,908	974	498
Total share-based compensation	$ 1,977	$ 2,602	$ 1,634

(1) In accordance with SFAS No. 123(R).
(2) In accordance with FIN 44.
(3) In accordance with APB No. 25.

As a result of adopting SFAS No. 123(R), the Company's loss before income taxes and net loss for 2006 was approximately $301,400 and $195,900 lower, respectively, than if the Company had continued to account for share-based compensation under APB No. 25. Basic and diluted loss per share for the year ended December 31, 2006 would have been $(2.36) if the Company had not adopted SFAS No. 123(R), compared to reported basic and diluted loss per share of $(2.38).

The Company receives a tax deduction for certain stock options exercised during the period the options are exercised, generally for the excess of the price at which the options are sold over the exercise prices of the options. In addition, the Company receives a tax deduction for restricted stock grants that vest during the period for the excess of the fair value on the vesting date compared to the grant date fair value. SFAS No. 123(R) requires that these excess tax benefits be reported in the consolidated statement of cash flows as financing activities. SFAS No. 123(R) provides that the excess tax benefit and credit to APIC for the windfall should not be recorded until the deduction reduces income taxes payable. Because the Company is in a net operating loss ("NOL") position for tax purposes, and does not have taxes payable at this time, it has not realized a tax benefit from the deduction. Therefore, the Company excludes these deductions from the windfall pool and does not present the tax benefits from the exercise of stock options as financing activities. As of December 31, 2006, $1.6 million of NOL carryforwards will be credited to APIC in future periods when the tax benefit is realized and reduces taxes payable.

Stock Options

There have been no stock option grants in 2006 or 2005. For future grants, the Company expects to use the Black-Scholes option pricing model to estimate the fair value of stock options which requires the Company to make the following assumptions:

- The risk-free interest rate is based on the applicable year Treasury bond at date of grant.
- The dividend yield on the Company's common stock is assumed to be zero since the Company does not pay dividends.

- The market price volatility of the Company's common stock is based on historical prices.
- The term of the grants is based on the simplified method as described in SAB No. 107, *Share-Based Payment.*

The assumptions above are based on multiple factors, including historical exercise patterns of employees in relatively homogenous groups with respect to exercise and post-vesting employment termination behaviors, expected future exercising patterns for these same homogeneous groups and the implied volatility of our stock price.

In addition, the Company estimates a forfeiture rate at the inception of the option grant based on historical data and adjusts this prospectively as new information regarding forfeitures becomes available.

For the year ended December 31, 2006, the Company recognized $68,937 in stock option compensation expense. All option grants were fully vested as of April 1, 2006; therefore, no further compensation expense associated with stock options will be expensed in future periods unless new grants are awarded. The total intrinsic value (current market price less the option strike price) of options exercised during the year ended December 31, 2006 was $1.5 million and the Company received $0.6 million in cash in connection with these exercises.

A summary of activity associated with the Company's stock options during the last three years follows:

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Contract Life	Aggregate Intrinsic Value
For the Year Ended December 31, 2004:				
Outstanding, beginning of period	1,171,512	$ 8.76		
Granted	50,000	13.99		
Exercised	(322,723)	6.24		
Forfeited	(76,739)	59.11		
Outstanding, end of period	822,050	5.91	5.79 years	$ 7,195,268
Exercisable, end of period	690,050	5.51	5.26 years	$ 6,316,658
For the Year Ended December 31, 2005:				
Outstanding, beginning of period	822,050	5.91		
Exercised	(86,600)	5.67		
Outstanding, end of period	735,450	5.93	4.80 years	$ 13,760,616
Exercisable, end of period	685,450	5.35	4.55 years	$ 13,227,866
For the Year Ended December 31, 2006:				
Outstanding, beginning of period	735,450	5.93		
Exercised	(84,750)	6.80		
Outstanding, end of period	650,700	5.82	3.92 years	$ 8,200,945
Exercisable, end of period	650,700	$ 5.82	3.92 years	$ 8,200,945

The fair value of options was measured at the date of grant using the Black-Scholes option-pricing model. There were no options granted or forfeited for the years ended December 31, 2006 and 2005. For the year ended

December 31, 2004, the weighted-average fair value of options granted during the year was $11.03 using the following weighted-average assumptions:

	For the Year Ended December 31, 2004
Risk free interest rate	3.76%
Dividend yield	None
Volatility factor of the expected market price of the Company's common stock	72%
Expected life of the options (in years)	10

The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions including the expected stock price volatility. The Company's stock options have characteristics significantly different for those of traded options and because changes in the subjective input assumptions can materially affect the fair value estimate, it is management's opinion that the valuations afforded by the existing models are different from the value that the options would realize if traded in the market.

A summary of additional information related to options outstanding as of December 31, 2006 follows:

All Options				Options Exercisable		
Range of Exercise Price	**Options Outstanding**	**Weighted Average Remaining Contractual Life (in years)**	**Weighted Average Exercise Price**	**Range of Exercise Price**	**Options Outstanding**	**Weighted Average Exercise Price**
$3.00 - $3.88	119,500	4.60	$3.52	$3.00-$3.88	119,500	$3.52
$4.22	200,000	2.00	$4.22	$4.22	200,000	$4.22
$5.18 - $5.73	160,500	5.33	$5.46	$5.18-$5.73	160,500	$5.46
$7.06 - $7.58	70,600	2.59	$7.12	$7.06-$7.58	70,600	$7.12
$8.88	50,000	4.00	$8.88	$8.88	50,000	$8.88
$13.50-$13.99	50,100	7.24	$13.99	$13.50-$13.99	50,100	$13.99

Restricted Stock

In addition to stock options, the Company issues restricted stock and restricted stock units. For awards issued to date, shares of common stock associated with the restricted stock awards will be issued, subject to continued employment, ratably over three or four years in accordance with the award's vesting schedule, beginning on the first or second anniversary of the date of grant. Compensation expense from restricted stock and restricted stock units is amortized over the vesting period and offset to APIC. The share-based expense for these awards was determined based on the market price of the Company's stock at the date of grant applied to the total number of shares that were anticipated to fully vest and then amortized over the vesting period. As of December 31, 2006, the Company had unamortized share-based compensation of $5.8 million associated with these awards. The cost is expected to be recognized over a weighted-average period of two years. The total fair value of shares vested during the year ended December 31, 2006 was $2.3 million. Upon adoption of SFAS No. 123(R), the Company recorded an immaterial cumulative effect of change in accounting principle as a result of the change in policy from recognizing forfeitures as they occur to recognizing expense based on its expectation of the awards that will vest over the requisite service period for its restricted stock and restricted stock unit awards. This amount was recorded as compensation cost in general and administrative expenses in the consolidated statement of operations.

The following table below summarizes restricted stock activity for the year ended December 31, 2006:

	Shares	Weighted-Average Price
Unvested restricted stock units at December 31, 2005	218,954	$ 14.90
Granted	333,600	19.32
Vested	(98,720)	13.14
Forfeited	(17,210)	21.02
Unvested restricted stock units at December 31, 2006	436,624	$ 18.43

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

	Year Ended December 31,		
	2006	2005	2004
	(in thousands, except per share amounts)		
Net income (loss)	$ (41,261)	$ 33,358	$ 15,129
Basic weighted average shares outstanding	17,368	17,122	13,029
Add: dilutive effect of employee stock options	--	498	477
Add: dilutive effect of restricted stock units	--	195	142
Diluted weighted-average common shares outstanding	17,368	17,815	13,648
Basic income (loss) per common share	$ (2.38)	$ 1.95	$ 1.16
Diluted income (loss) per common share	$ (2.38)	$ 1.87	$ 1.11

Associated with the exercise of stock options, the Company received a tax benefit of approximately $461,900, $507,300 and $462,000 in 2006, 2005 and 2004, respectively. The tax benefit is recorded as an increase in additional paid-in capital.

18. RELATED PARTY TRANSACTIONS

The transactions described below were with affiliates, and 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 Connecticut general partnership composed of the three Connecticut limited partnerships (Edge I, L.P., Edge II, L.P., and Edge III, L.P.) whose general partners are Mr. Sfondrini and a corporation wholly-owned by him; 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 (a director of the Company), 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. In September 2006, the Essex I and Essex II Joint Ventures sold all of their interests in wells operated by the Company except for one well in which Essex II has a 1% gross working interest. The gross amounts paid or accrued to these persons and entities by the Company in 2006 (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 Including Overriding Royalty (1)		
	2006	2005	2004
Andex Corporation /Texedge Corporation	$ 4,375	$ 2,516	$ 3,896
Bamaedge, L.P.	1,447	2,057	3,594
Edge Group Partnership	428,321	291,773	387,603
Edge Holding Co., L.P.	76,169	54,048	71,177
Essex I Royalty Joint Venture	18,641	23,887	32,603
Essex II Royalty Joint Venture	112,912	79,781	150,509
Jovin, L.P.	--	--	--
Stanley Raphael	4,268	3,630	5,209
Total	$ 646,133	$ 457,692	$ 654,591

(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, maintains an indirect interest in these entities.

Owner	Lease Operating Expenses Paid to the Company by Owners		
	2006	2005	2004
Andex Corporation /Texedge Corporation	$ --	$ --	$ 2,578
Bamaedge, L.P.	318	--	--
Edge Group Partnership	308,516	66,146	40,284
Edge Holding Co., L.P.	54,422	12,711	7,065
Essex I Royalty Joint Venture	--	--	--
Essex II Royalty Joint Venture	64,248	13,114	5,629
Jovin, L.P.	--	--	--
Stanley Raphael	2,595	659	412
Total	$ 430,099	$ 92,630	$ 55,968

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

A summary of non-cash investing and financing activities for the years ended December 31, 2006, 2005 and 2004 is presented below:

Description	Number of shares issued		Fair Market Value
2006:	*(in thousands)*		
Shares issued to satisfy restricted stock grants	119	$	1,803
Shares issued to fund the Company's matching contribution under the Company's 401(k) plan	22	$	429
2005:			
Shares issued to satisfy restricted stock grants	59	$	570
Shares issued to fund the Company's matching contribution under the Company's 401(k) plan	10	$	168
2004:			
Shares issued to satisfy restricted stock grants	70	$	447
Shares issued to fund the Company's matching contribution under the Company's 401(k) plan	8	$	112

For the years ended December 31, 2006, 2005 and 2004, the non-cash portion of Asset Retirement Costs was $0.4 million, $0.4 million, and $0.3 million, respectively. A supplemental disclosure of cash flow information for the years ended December 31, 2006, 2005 and 2004 is presented below:

	For the Year Ended December 31,					
	2006		2005		2004	
Cash paid during the period for:			*(in thousands)*			
Interest, net of amounts capitalized	$	1,959	$	--	$	331
Federal alternative minimum tax payments		94		327		--

20. 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 (1)	Second Quarter	First Quarter
	(in thousands, except per share amounts)			
2006:				
Oil and natural gas revenue	$ 24,931	$ 35,941	$ 33,878	$ 34,994
Operating expenses	(19,364)	(122,619)	(24,389)	(23,695)
Operating income (loss)	5,567	(86,678)	9,489	11,299
Other expense, net	(478)	(809)	(554)	(672)
Income tax (expense) benefit	(2,157)	30,607	(3,140)	(3,735)
Net income (loss)	$ 2,932	$ (56,880)	$ 5,795	$ 6,892
Basic earnings (loss) per share	$ 0.17	$ (3.27)	$ 0.33	$ 0.40
Diluted earnings (loss) per share	$ 0.16	$ (3.27)	$ 0.32	$ 0.38
2005:				
Oil and natural gas revenue	$ 42,444	$ 29,585	$ 26,210	$ 22,944
Operating expenses	(21,943)	(17,083)	(15,056)	(15,640)
Operating income	20,501	12,502	11,154	7,304
Other expense, net	(3)	(8)	(11)	(3)
Income tax expense	(7,216)	(4,351)	(3,934)	(2,577)
Net income	$ 13,282	$ 8,143	$ 7,209	$ 4,724
Basic earnings per share	$ 0.77	$ 0.47	$ 0.42	$ 0.28
Diluted earnings per share	$ 0.74	$ 0.45	$ 0.41	$ 0.27

(1) Operating expenses in the third quarter of 2006 include a $96.9 million ($63.0 million, net of tax) non-cash impairment charge as a result of a full-cost ceiling test write down. See the full-cost ceiling test discussion in Note 2.

21. 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 relating to the Company's oil and natural gas producing activities, all of which are conducted within the continental United States, are summarized below:

	As of December 31, 2006	As of December 31, 2005
	(in thousands)	
Developed oil and natural gas properties	$ 521,713	$ 401,697
Unevaluated oil and natural gas properties	57,577	36,949
Accumulated depletion	(290,863)	(133,449)
Net capitalized cost	$ 288,427	$ 305,197

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

	For the Year Ended December 31, 2006	2005	2004
		(in thousands)	
Acquisition cost:			
Unproved properties	$ 21,661	$ 33,948	$ 12,163
Proved properties (1)	36,573	66,472	33,980
Exploration costs	17,898	20,426	8,297
Development costs (2)	65,140	59,121	34,827
Total costs incurred	$ 141,272	$ 179,967	$ 89,267

(1) Includes $17.8 million added to property acquired in the Cinco acquisition in 2005 associated with recording a deferred tax liability at the date of acquisition for taxable temporary differences existing at the purchase date in accordance with SFAS No. 109. This amount was adjusted to $16.8 million in 2006 as a result of the final purchase price adjustment for the Cinco acquisition. See Notes 6 and 15.

(2) Included in the development costs line item are the asset retirement costs associated with the plugging and abandonment liability related to SFAS No. 143 (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:

	For the Year Ended December 31, 2006	2005	2004
		(in thousands)	
Oil and natural gas revenue	$ 129,744	$ 121,183	$ 64,505
Operating expenses:			
Oil and natural gas operating expenses and ad valorem taxes	11,836	10,102	5,356
Production taxes	6,421	6,966	3,953
Accretion expense	189	141	99
Depletion expense	60,472	39,810	21,472
Income tax expense	17,721	22,551	11,870
Results of operations from oil and gas producing activities	$ 33,105	$ 41,613	$ 21,755

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) For the Year Ended December 31,		
	2006	2005	2004
Proved developed and undeveloped reserves		(in thousands)	
Beginning of year	82,290	66,311	46,824
Revisions of previous estimates	(13,526)	(7,737)	(5,993)
Purchase of oil and gas properties	12,083	10,168	14,803
Extensions and discoveries	9,202	26,145	19,825
Sales of natural gas properties	(52)	--	--
Production	(13,850)	(12,597)	(9,148)
End of year	76,147	82,290	66,311
Proved developed reserves at year end	60,163	59,066	50,698

	Oil, Condensate and Natural Gas Liquids(Bbls) For the Year Ended December 31,		
	2006	2005	2004
Proved developed and undeveloped reserves		(in thousands)	
Beginning of year	3,410	3,792	2,851
Revisions of previous estimates	675	(640)	(106)
Purchase of oil and gas properties	322	114	268
Extensions and discoveries	502	775	1,270
Sales of natural gas properties	(17)	--	--
Production	(567)	(631)	(491)
End of year	4,325	3,410	3,792
Proved developed reserves at year end	3,158	2,852	2,698

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, 2006 is shown below:

	For the Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Future cash inflows	$ 616,605	$ 949,752	$ 521,263
Future oil and natural gas operating expenses	(131,926)	(192,550)	(118,492)
Future development costs	(75,389)	(79,651)	(31,795)
Future income tax expense	(65,738)	(173,019)	(75,095)
Future net cash flows	343,552	504,532	295,881
10% discount factor	(110,346)	(160,742)	(79,010)
Standardized measure of discounted future net cash flows	$ 233,206	$ 343,790	$ 216,871

In accordance with SEC regulations, the oil and natural gas prices in effect at December 31, 2006, adjusted for basis and quality differentials, are applied to year-end quantities of proved oil and natural gas reserves to compute future cash flows. The base prices before adjustments were $5.62 per MMbtu of natural gas, $36.64 per Bbl of natural gas liquids and $61.06 per Bbl of oil.

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:

	For the Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Changes due to current year operations:			
Sales of oil and natural gas, net of oil and natural gas operating expenses	$ (101,520)	$ (105,638)	$ (56,969)
Sales of oil and natural gas properties	(618)	--	--
Purchase of oil and gas properties	34,855	58,022	65,403
Extensions and discoveries	42,085	119,850	65,467
Changes due to revisions of standardized variables:			
Prices and operating expenses	(190,802)	143,600	17,648
Revisions of previous quantity estimates	(29,018)	(54,208)	(21,190)
Estimated future development costs	44,992	14,054	(15,962)
Income taxes	72,792	(74,281)	(9,190)
Accretion of discount	34,379	21,687	15,217
Production rates (timing) and other	(17,729)	3,833	4,280
Net change	(110,584)	126,919	64,704
Beginning of year	343,790	216,871	152,167
End of year	$ 233,206	$ 343,790	$ 216,871

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.

INDEX TO EXHIBITS

Exhibit No.

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 as of October 7, 2004 (Incorporated by reference from exhibit 2.1 to the Company's Current Report on Form 8-K filed October 12, 2004).

2.4 — Purchase and Sale Agreement, dated as of September 21, 2005 among Pearl Energy Partners, Ltd., and Cibola Exploration Partners, L.P., as Sellers; and Edge Petroleum Exploration Company as Buyer and Edge Petroleum Corporation as Guarantor (Incorporated by reference from exhibit 2.1 to the Company's Current Report on Form 8-K filed October 19, 2005).

2.5 — Stock Purchase Agreement by and among Jon L. Glass, Craig D. Pollard, Leigh T. Prieto, Yorktown Energy Partners V, L.P., Yorktown Energy Partners VI, L.P., Cinco Energy Corporation, and Edge Petroleum Exploration Company and Edge Petroleum Corporation, dated as of September 21, 2005 (Incorporated by reference from exhibit 2.5 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2005).

2.6 — Letter Agreement dated November 18, 2005 by and among Edge Petroleum Exploration Company, Cinco Energy Corporation and Sellers (Incorporated by reference from exhibit 2.02 to the Company's Current Report on Form 8-K filed December 6, 2005). Pursuant to Item 601(b)(2) of Regulation S-K, the Company had omitted certain Schedules to the Letter Agreement (all of which are listed therein) from this Exhibit 2.6. It hereby agrees to furnish a supplemental copy of any such omitted item to the SEC on its request.

3.1 — Restated Certificate of Incorporation of the Company effective January 27, 1997 (Incorporated by reference from exhibit 3.1 to the Company's Current Report on Form 8-K filed April 29, 2005).

3.2 — Certificate of Amendment to the Restated Certificate of Incorporation of the Company effective January 31, 1997 (Incorporated by reference from exhibit 3.2 to the Company's Current Report on Form 8-K filed April 29, 2005).

3.3 – Certificate of Amendment to the Restated Certificate of Incorporation of the Company effective April 27, 2005 (Incorporated by reference from exhibit 3.3 to the Company's Current Report on Form 8-K filed April 29, 2005).

3.4 — 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).

3.5 — First Amendment to Bylaws of the Company on September 28, 1999 (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).

3.6 — Second Amendment to Bylaws of the Company on May 7, 2003 (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).

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 — Agreement and Amendment No. 1 to Third Amended and Restated Credit Agreement dated May 31, 2005 among Edge Petroleum Corporation, Edge Petroleum Exploration Company, Edge Petroleum Operating Company, Inc., Miller Exploration Company and Miller Oil Corporation, as borrowers, the lenders thereto and Union Bank of California, N.A., a national banking association, as agent for the lenders (Incorporated by reference from Exhibit 4.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2005).

4.3 — Agreement and Amendment No. 2 to the Third Amended and Restated Credit Agreement dated November 30, 2005 among Edge Petroleum Corporation, Edge Petroleum Exploration Company, Edge Petroleum Operating Company, Inc., Miller Oil Corporation, Miller Exploration Company, and Cinco Energy Corporation, as borrowers, the lenders thereto and Union Bank of California, N.A., a national banking association, as Agent (Incorporated by reference from Exhibit 4.3 to the Company's Annual Report on Form 10-K for the year ended December 31, 2005 (File No. 000-22149)).

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)).

4.8 — Fourth Amended and Restated Credit Agreement dated January 31, 2007 by and among Edge Petroleum Corporation, as borrower, and Union Bank of California, N.A., as Administrative Agent and Issuing Lender, and the other lenders party thereto (Incorporated by reference from exhibit 4.1 to Edge's Current Report on Form 8-K filed on February 5, 2007).

†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 — Amended and Restated Incentive Plan of Edge Petroleum Corporation as Amended and Restated Effective as of August 1, 2006 (Incorporated by reference from exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the six months ended June 30, 2006).

†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 therein (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 Certain Other Compensation of Executive Officers.

†10.14 – Description of Annual Cash Bonus Program for Executive Officers (Incorporated by reference from Exhibit 10.2 to the Company's Current Report on Form 8-K filed March 12, 2007).

†10.15 — New Base Salaries and Long-Term Incentive Awards for Certain Executive Officers (Incorporated by reference from exhibit 10.1 to the Company's Current Report on Form 8-K filed August 25, 2006).

10.16 — Purchase and Sale Agreement between Smith Production, Inc., as seller, and Edge Petroleum Exploration Company, as purchaser, dated November 16, 2006 (Incorporated by reference to exhibit 10.1 to Edge's Current Report on Form 8-K filed January 16, 2007).

10.17 — Purchase and Sale Agreement between Smith Production, Inc., as seller, and Edge Petroleum Exploration Company, as purchaser, dated November 16, 2006 (Incorporated by reference to exhibit 10.2 to Edge's Current Report on Form 8-K filed January 16, 2007).

10.18 — First Amendment of Purchase and Sale Agreement between Smith Production, Inc., as seller, and Edge Petroleum Exploration Company, as purchaser, dated December 15, 2006 (Incorporated by reference to exhibit 10.3 to Edge's Current Report on Form 8-K filed January 16, 2007).

10.19 — Second Amendment of Purchase and Sale Agreement between Smith Production, Inc., as seller, and Edge Petroleum Exploration Company, as purchaser, dated January 15, 2007 (Incorporated by reference to exhibit 10.1 to Edge's Current Report on Form 8-K filed January 19, 2007).

10.20 — First Amendment of Purchase and Sale Agreement between Smith Production, Inc., as seller, and Edge Petroleum Exploration Company, as purchaser, dated January 15, 2007 (Incorporated by reference to exhibit 10.2 to Edge's Current Report on Form 8-K filed January 19, 2007).

10.21 — Third Amendment of Purchase and Sale Agreement between Smith Production, Inc., as seller, and Edge Petroleum Exploration Company, as purchaser, dated January 31, 2007 (Incorporated by reference to exhibit 10.6 to Edge's Current Report on Form 8-K filed February 7, 2007).

10.22 — Certificate of Designations establishing the 5.75% Series A cumulative convertible perpetual preferred stock, dated January 27, 2007 (Incorporated by reference to exhibit 3.1 to Edge's Current Report on Form 8-K filed January 30, 2007).

10.23 – Purchase and Sale Agreement between Kerr-McGee Oil & Gas Onshore, L.P., as Seller, and Edge Petroleum Production Company, as Purchaser, and Edge Petroleum Corporation, as Additional Purchaser dated December 12, 2006 (Incorporated by reference from exhibit 2.1 to the Company's Current Report on Form 8-K filed December 18, 2006).

*12.1 — Statement of Computation of Ratio of Earnings to Fixed Charges.

*21.1 — Subsidiaries of the Company.

*23.1 — Consent of BDO Seidman, LLP.

23.2 — Consent of Ryder Scott Company (Incorporated by reference from exhibit 23.1 to the Company's Current Report on Form 8-K filed January 23, 2007).

23.3 — Consent of W.D. Von Gonten & Co. (Incorporated by reference from exhibit 23.2 to the Company's Current Report on Form 8-K filed January 23, 2007).

*23.4 — Consent of Ryder Scott Company.

*31.1 — Certification by John W. Elias, Chief Executive Officer, pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.

*31.2 — Certification by Michael G. Long , Chief Financial and Accounting Officer, pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.

*32.1	—	Certification by John W. Elias, Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code).
*32.2	—	Certification by Michael G. Long, Chief Financial and Accounting Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code).
99.1	—	Summary of Reserve Report of Ryder Scott Company Petroleum Engineers as of December 31, 2006 (Incorporated by reference from exhibit 99.1 to the Company's Current Report on Form 8-K filed January 23, 2007).
99.2	—	Summary of Reserve Report of W. D. Von Gonten & Co. Petroleum Engineers as of December 31, 2006 (Incorporated by reference from exhibit 99.2 to the Company's Current Report on Form 8-K filed January 23, 2007).
99.3	—	Oversight review letter of Ryder Scott Company Petroleum Engineers dated January 11, 2007 (Incorporated by reference from exhibit 99.2 to the Company's Current Report on Form 8-K filed January 16, 2007).
*99.4	—	Supplemental Summary of Reserve Report of Ryder Scott Company Petroleum Engineers as of December 31, 2006.

* Filed herewith.

† Denotes management or compensatory contract, arrangement or agreement.

EXHIBIT 31.1

CERTIFICATIONS

Principal Executive Officer

I, John W. Elias, certify that:

1. I have reviewed this annual report on Form 10-K of Edge Petroleum Corporation (the "registrant").
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 12, 2007

/s/ John W. Elias

John W. Elias
President, Chief Executive Officer
and Chairman of the Board

EXHIBIT 31.2

Principal Financial Officer

I, Michael G. Long, certify that:

1. I have reviewed this annual report on Form 10-K of Edge Petroleum Corporation (the "registrant").
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 12, 2007

/s/ Michael G. Long

Michael G. Long
Senior Vice President and Chief
Financial and Accounting Officer

EXHIBIT 32.1

Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002
(Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code)

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code), I, John W. Elias, Chief Executive Officer of Edge Petroleum Corporation, a Delaware corporation (the "Company"), hereby certify, to my knowledge, that:

(1) the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2006 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 12, 2007

/s/ John W. Elias
Name: John W. Elias
Chief Executive Officer

EXHIBIT 32.2

Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002
(Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code)

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code), I, Michael G. Long, Chief Financial Officer of Edge Petroleum Corporation, Inc., a Delaware corporation (the "Company"), hereby certify, to my knowledge, that:

(1) the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2006 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 12, 2007

/s/ Michael G. Long
Name: Michael G. Long
Chief Financial and Accounting Officer

EDGE PETROLEUM CORPORATION

April 19, 2007

Dear Stockholder:

You are cordially invited to join us at the annual meeting of stockholders of Edge Petroleum Corporation. The meeting will again be held at the Hyatt Regency Hotel, 1200 Louisiana Street, Houston, Texas 77002, on Wednesday, May 23, 2007 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. In addition, the reports that accompany this notice address the Company's performance over the past year. I hope you will find them helpful in answering any questions you have about the Company.

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.

You may notice that the format of this year's proxy statement is considerably different than in past years and conforms to new Securities and Exchange Commission regulations. These new regulations are designed to foster a more transparent means of communication with our stockholders, especially regarding our compensation practices and performance.

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.

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

John W. Elias

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

NOTICE OF ANNUAL MEETING OF STOCKHOLDERS
TO BE HELD ON MAY 23, 2007

To the Stockholders of
Edge Petroleum Corporation

The annual meeting of stockholders of Edge Petroleum Corporation will be held at the Hyatt Regency Hotel, 1200 Louisiana Street, Houston, Texas 77002, on Wednesday, May 23, 2007 at 10:00 a.m. Houston time, for the following purposes:

1. To elect two directors.

2. To ratify the selection of BDO Seidman, LLP as the Company's independent registered public accounting firm for 2007.

3. To transact such other business as may properly come before the meeting or any adjournment thereof.

The Board of Directors has fixed the close of business on April 5, 2007 as the record date for determining stockholders entitled to notice of, and to vote at, this meeting.

You are cordially invited to attend the meeting in person. 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. Submitting your proxy early by any of these methods will not prevent you from voting your shares at the meeting if you desire to do so, as your proxy is revocable at your option.

By Authorization of the Board of Directors

Robert C. Thomas

ROBERT C. THOMAS
Sr. Vice President, General Counsel and
Corporate Secretary

April 19, 2007
1301 Travis Street, Suite 2000
Houston, Texas 77002

Proxy Statement for the

Annual Meeting of Stockholders of

EDGE PETROLEUM CORPORATION

To be Held on Wednesday, May 23, 2007

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PROXY STATEMENT

This Proxy Statement and the accompanying proxy card are being mailed to stockholders beginning on or about April 19, 2007. 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 2007 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 directors of the nominees listed herein, **FOR** approval of the appointment of BDO Seidman, LLP as the Company's independent registered public accounting firm for 2007, 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 43 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 April 5, 2007, the record date for determining stockholders entitled to vote at the Annual Meeting, the Company had outstanding and entitled to vote 28,454,438 shares of Common Stock. Although the Company has issued convertible Preferred Stock and 2,875,000 shares of convertible Preferred Stock are outstanding as of the record date, Common Stock is the only class of stock of the Company entitled to vote at the Annual Meeting. Each share of Common Stock 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 does not vote on a particular matter because the broker has not received voting instructions from the beneficial owner and does not have the discretion under stock exchange rules to vote the shares in the absence of instructions. 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 and ratification of auditors. The Company has no non-routine matters currently planned to put before the stockholders at this Annual Meeting. 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 case of a proposal where the vote required is the approval of a majority of votes. 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, 2006, 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 2006 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 April 5, 2007, or you must provide a copy of a brokerage statement or other evidence of beneficial ownership showing ownership of common stock on April 5, 2007. 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 in order to expedite your admission to the meeting.

PROPOSAL I

Election of Directors

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.

Two directors are to be elected to the class of directors whose current term will end in 2007. The names of Messrs. Robert W. Shower and David F. Work will be placed in nomination, and the persons named in the proxy will vote in favor of such nominees unless authority to vote in the election of a director is withheld. Messrs. Shower and Work are currently directors of the Company. Mr. Stanley Raphael's term as a director is also ending in 2007, and Mr. Raphael will be retiring from the Board at the conclusion of his term. Upon Mr. Raphael's retirement, the Board will have eight members. The Company, on behalf of itself and the stockholders, would like to express its heart-felt appreciation to Mr. Raphael for his dedicated service as a Director of the Company and its predecessor entities for the last 16 years.

The persons named in the proxy may act with discretionary authority in the event any nominee should become unavailable for election, although management is not currently aware of any circumstances likely to result in a nominee becoming unavailable for election. In accordance with the Company's Bylaws, the two directors 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 one or more of the named nominees.

Nominees

The following summaries set forth information concerning each of the nominees 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.

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. From November 2005 until February 2007, Mr. Shower served as a director of Regency GP, LLC, which is the general partner and manager of Regency Energy Partners LP, a publicly traded limited partnership engaged in midstream energy operations, including gathering, processing, marketing and transportation of natural gas and natural gas liquids. Mr. Shower is Chairman of the Audit Committee and a member of the Compensation Committee of the Board. He is 69 years old.

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 Houston regional president of BP and Executive Vice President of Amoco. 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 Chairman of the Corporate Governance/Nominating Committee and is a member of the Compensation Committee of the Board. He is 61 years old.

The Board of Directors recommends that stockholders vote FOR the election of Messrs. Shower and Work as directors of the Company whose terms will expire in 2010.

Directors with Terms Expiring in 2008 and 2009

The following summaries set forth information concerning six directors of the Company whose present terms of office will continue until 2008 or 2009, including each director'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. 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 Private Capital Advisors, Inc. and Vincent Andrews Management Corporation, privately-held management companies primarily involved in personal financial management. Mr. Andrews is a member of the Audit Committee of the Board. He is 66 years old. Mr. Andrews' current term as a director expires in 2008.

Jonathan M. Clarkson was appointed by the Board of Directors as a director of the Company on October 27, 2005. Since 2003, Mr. Clarkson has served as President, Houston Region, of Texas Capital Bank. From May 2001 to October 2002, Mr. Clarkson served as President, Chief Financial Officer and a director of Mission Resources Corp., an independent oil and gas exploration and production company. From 1999 through 2001, Mr. Clarkson served as President, Chief Operating Officer and a director of Bargo Energy Company, a private company engaged in the acquisition and exploitation of onshore oil and natural gas properties, which merged with Mission Resources in May

2001. Mr. Clarkson serves on the Audit and Compensation Committees of the Board. He is 57 years old. Mr. Clarkson's current term as a director expires in 2008.

Michael A. Creel was appointed by the Board of Directors as a director of the Company on October 27, 2005. Since January 2001, Mr. Creel has served as the Executive Vice President & Chief Financial Officer of Enterprise Products GP, LLC, the general partner of Enterprise Products Partners L.P., a publicly traded limited partnership that owns and operates midstream energy assets. Since February 2006, Mr. Creel has also served as a director for Enterprise Products GP, LLC, and from 2000 to 2001 served as its Senior Vice President and Chief Financial Officer. Since April 2005, he also has served as the President and Chief Executive Officer and a director of EPE Holdings, LLC, the general partner of Enterprise GP Holdings, L.P., a publicly traded limited partnership that owns and operates Enterprise Products GP, LLC. From February to December 2006, Mr. Creel served on the board of Texas Eastern Products Pipeline Company, LLC, the general partner of TEPPCO Partners, L.P. Since October 2006, Mr. Creel has served as director, Executive Vice President and Chief Financial Officer of DEP Holdings, LLC, the general partner of Duncan Energy Partners, L.P., a publicly traded limited partnership that owns and operates midstream energy assets. Mr. Creel serves on the Audit and Corporate Governance/Nominating Committees of the Board. He is 53 years old. Mr. Creel's current term as a director expires in 2008.

Thurmon M. Andress has served as a director of the Company since November 2002. Since 1998, he has served as Managing Director-Houston of Breitburn Energy Company, LP and also currently serves on that company's board of directors. Breitburn Energy Company, LP (a wholly-owned subsidiary of Provident Energy Trust, a Canadian royalty trust) is engaged in oil and gas production, with operations primarily in California and Wyoming. Since October 2006, Mr. Andress has served on the board of directors of EPE Holdings, LLC, the general partner of Enterprise GP Holdings, LP, a publicly-traded limited partnership, and serves on EPE Holdings' audit, conflicts and governance board committee. Since 2005, Mr. Andress has served as managing partner of a family-owned partnership, Andress Oil & Gas LLP, which has various oil and gas interests and overriding royalty interests. Mr. Andress has over 45 years of experience in the oil and gas industry. He is Chairman of the Compensation Committee and also currently serves on the Audit Committee of the Board. He is 73 years old. Mr. Andress' current term as a director expires in 2009.

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 45 years of experience in the oil and natural gas exploration and production business. He is 66 years old. Mr. Elias' current term as a director expires in 2009.

John Sfondrini has served as a director of the Company since December 1996 and prior to that he served 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 served on the Corporate Governance/Nominating Committee of the Board in 2006 through early 2007. He is 58 years old. Mr. Sfondrini's current term as a director expires in 2009.

CORPORATE GOVERNANCE

Corporate Governance Guidelines

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 stockholders;

and other matters (the "Corporate Governance Guidelines"). The Corporate Governance Guidelines of the Company detail the methodology used by the Committee to determine director independence and a copy of those Guidelines can be found on the Company's website, http://www.edgepet.com, by first clicking on "About Us" and then on "Corporate Governance."

Director Independence

The Board, at its meeting held on February 1, 2007, 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, and except that Mr. Sfondrini is not independent because of certain transactions described under "Transactions with Related Persons" later in this proxy statement. 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 took into consideration certain relationships, described below, in making its determinations as to which directors are independent. These relationships are not of a nature or significance such that they are required to be disclosed under the requirements applicable to the "Transactions With Related Persons" section of this proxy statement. The Board's opinion was that the following relationships would not interfere with the exercise of independent judgment on the part of the director in carrying out his responsibilities as a director:

- Mr. Andrews, together with Mr. Sfondrini, control BV Partners Limited Partnership, one of the partnerships involved in a sale of oil and gas assets to the Company described in the "Transactions With Related Persons" section of this proxy statement. Mr. Andrews owns no limited partner interest in BV Partners Limited Partnership, and his ownership in the corporate general partner is not material in size or economic value.
- Mr. Raphael, personally, and two corporations, of which Mr. Andrews is an officer and a member of his immediate family hold ownership interests, own working interests in certain wells and prospects operated by the Company. These working interests bear their share of lease operating costs and royalty burdens on the same basis as the Company. Amounts paid by the Company to these parties represent their pro-rata ownership shares in the particular properties involved. These working interests are immaterial in amount.
- Mr. Raphael and a limited partnership, of which one of the corporations affiliated with Mr. Andrews is the general partner, hold overriding royalty interests with respect to the Company's working interest in certain wells and prospects. As a result the Company pays royalties to these parties. These overriding royalty interests are immaterial in amount.

Director Nomination Process

Identifying Candidates. The Corporate Governance/Nominating Committee considers candidates for Board membership suggested by its members and other Board members, as well as management and stockholders. The Committee may engage third parties to whom a fee is paid to assist it in identifying or evaluating any potential nominee; however, no such third party was used in the past year. All director nominations made by the Board must be recommended by the Corporate Governance/Nominating Committee and approved by a majority of the non-employee 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. 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" in this proxy statement.

Qualifications. 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 Committee's 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 Committee, Compensation Committee 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 turned 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. In December 2005, the Board also considered and approved a resolution waiving the director age restriction as it relates to Mr. Andress to allow him to stand for re-election to the Board of Directors at the 2006 Annual Meeting, at which time he was 72 years of age. The Board felt that each of Messrs. Andress and Elias brings a level of experience, expertise and involvement within the industry that is a valuable and important component in the continued execution of Edge's strategic business plan and that these waivers were in the best interests of the Company. The Board may, in the future, 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.

Candidate Selection Process. Once the Committee identifies a prospective nominee, it will make an initial determination as to whether to conduct a full evaluation of the prospective candidate. This initial determination will be based on whatever information is provided to the Committee concerning 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 further pursue the prospective nominee, the Committee will evaluate the individual 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 Committee's recommendations are not binding on 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.

Security-holder Communications with the Board

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.

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 the Company's business.

MEETINGS AND COMMITTEES OF THE BOARD

The Board

The Company expects each Director to devote sufficient time, energy and attention to ensure diligent performance of his or her duties and 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 who were serving as Directors at that time attended last year's annual meeting of stockholders.

During 2006, the Board of Directors held nine meetings and acted by written consent two times. All members of the Board of Directors attended at least 75% of the meetings of the Board and of the committees on which they served during 2006. In addition, the Company's non-employee Directors meet at regularly scheduled executive sessions without management present. In 2006, the Board held four regularly scheduled executive sessions in which only the independent Directors were present.

Committees of the Board

The Board has a standing Audit Committee, Compensation Committee and Corporate Governance/Nominating Committee to facilitate and assist it in the execution of its responsibilities. Charters for each committee, as well as the Corporate Governance Guidelines, are available on the Company's website at www.edgepet.com by first clicking on "About Us" and then "Corporate Governance." The charters, as well as the Corporate Governance Guidelines, are also available in print upon request to any stockholder. 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. The table below shows current membership for each of these Board committees:

Audit Committee	Corporate Governance/ Nominating Committee	Compensation Committee
Thurmon M. Andress	Michael A. Creel	Thurmon M. Andress*
Vincent S. Andrews	Stanley S. Raphael	Jonathan M. Clarkson
Jonathan M. Clarkson	David F. Work*	Robert W. Shower
Michael A. Creel		David F. Work
Robert W. Shower*		

*Committee Chairman

Mr. Sfondrini resigned from the Corporate Governance/Nominating Committee in early 2007.

Audit Committee. The Audit Committee has five members and met five times in 2006. Each of Messrs. Andress, Andrews, Clarkson, Creel and Shower 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. In addition, the Board has determined that at least three members of the Audit Committee, Messrs. Clarkson, Creel and Shower, are "audit committee financial experts." Each of them has experience as a principal financial officer, as described in their biographies earlier in this proxy statement. Mr. Shower has also served on the audit committees of other public companies and has experience as a public accountant.

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 contractual 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; and 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 also reviews and approves all related party transactions to the extent required by Nasdaq rules. 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"), which is available on the Company's website at www.edgepet.com, by first clicking on "About Us" and then "Corporate Governance." The charter is also available in print to any stockholder who requests it.

Compensation Committee. The Compensation Committee has four members and met four times in 2006. The Compensation Committee has regularly scheduled meetings throughout the year, but also meets telephonically as necessary to perform its duties and responsibilities. The Compensation Committee generally meets in executive session at regularly scheduled meetings. The Compensation Committee is comprised solely of non-employee Directors, all of whom the Board has determined are 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"), which is available on the Company's website at www.edgepet.com, by first clicking on "About Us" and then "Corporate Governance." The charter is also available in print to any stockholder who requests it. The duties and functions performed by the Compensation Committee are:

- to review and recommend to the Board of Directors for ratification or determine the annual salary, bonus, equity awards and other benefits, direct and indirect, of the executive officers;
- to review new executive compensation programs and review on a periodic basis the operation of the Company's executive compensation programs to determine whether they are properly coordinated;
- to 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;
- to establish and periodically review policies in the area of management perquisites; and
- 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.

The agenda for meetings of the Compensation Committee is prepared by the Company's Chief Executive Officer and Compensation Committee meetings are regularly attended by him. Depending on the agenda for the particular meeting, these materials may include:

- Company organizational charts, department job titles and grade levels;
- recommended salary rate ranges for each job grade level;
- recommended performance and promotion budget;
- recommended targeted bonus opportunities for each employee, including the executive officers other than the Chief Executive Officer;
- summary of severance obligations in event of a change in control;
- summary of stock grants and options for directors and employees;

- financial reports on year-to-date performance versus budget and compared to prior year performance; and
- performance reviews and other reports on levels of achievement of individual and corporate performance objectives.

The Compensation Committee's Chairman reports the Committee's recommendations on executive compensation to the Board. The Compensation Committee may delegate authority to fulfill certain administrative duties regarding the compensation programs and has delegated that authority to the Company's Human Resources Department and Mr. Elias. Mr. Elias has also been delegated authority to grant certain performance and hiring equity grants under the Incentive Plan to, and to adjust the salaries of, non-executive officers and other employees. In addition, the Committee has authority under its charter to engage the services of outside advisors, experts and others to assist the Committee. 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 provided by the Mercer Energy Survey (described below in "Executive Compensation-Compensation Discussion and Analysis-Role of Executive Officers in Compensation Decisions").

Management plays a significant role in the compensation-setting process by

- evaluating employee performance;
- recommending Company performance targets and objectives to the Committee;
- recommending salary, bonus and restricted stock grant levels to the Committee.

Corporate Governance/Nominating Committee. In 2006, the Corporate Governance/Nominating Committee had four members[1] and met two times. The Committee is currently comprised of three non-employee Directors, all of whom the Board has determined are independent within the meaning of Marketplace Rule 4200(a)(15) of the Nasdaq Stock Market. 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, which is available on the Company's website at www.edgepet.com by first clicking on "About Us" and then "Corporate Governance." The charter is also available in print to any stockholder who requests it. 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;
- makes recommendations on director compensation to the Board; and
- perform any other duties that may be assigned by the Board from time to time.

Compensation Committee Interlocks and Insider Participation

The members of the Compensation Committee of the Board of Directors are Messrs. Andress (Chairman), Clarkson, Shower and Work. 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.

Audit Committee Report

As noted above, the Audit Committee is currently composed of five Directors, Messrs. Andress, Andrews, Clarkson, Creel and Shower, each of whom is independent as defined by the Nasdaq Stock Market's listing standards.

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[1] Mr. Sfondrini served on the Committee in 2006 through the beginning of 2007.

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, 2006 financial statements. Management represented to the Audit Committee that the Company's consolidated financial statements were prepared in accordance with generally accepted accounting principles in the United States of America. 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, 2006, filed with the SEC.

The Audit Committee:

Robert W. Shower, Chair
Thurmon Andress
Vincent S. Andrews
Jonathan M. Clarkson
Michael A. Creel

Pursuant to the SEC Rules, the foregoing Audit Committee Report is not deemed "soliciting material", is not "filed" with the SEC 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.

DIRECTOR COMPENSATION

We use a combination of cash and stock-based incentive compensation to attract and retain qualified candidates to serve on the Board. In setting director compensation, the Board considers the significant amount of time that Directors expend in fulfilling their duties to the Company, as well as the skills required by the Company of members of the Board.

Annual Retainer

Effective June 1, 2006, each Non-employee member of the Board receives an annual retainer, which is paid in arrears on or following the annual meeting of stockholders, of $20,000 payable in cash and $50,000 payable in Common Stock of the Company, valued as of the award date (subject to rounding up or down such that the number of shares issued to each Director is a whole number, but not to exceed $50,000 in value), pursuant to the Edge Petroleum Corporation Incentive Plan, as amended and restated (the "Incentive Plan"). Following the 2006 annual meeting of stockholders, each Non-employee member of the Board received a retainer payment consisting of $20,000 cash and 2,511 shares of Common Stock. Under the Incentive Plan, the annual stock awards to non-employee Directors are made as of the first business day of the month following the annual meeting of stockholders. Accordingly, the stock, which was immediately fully vested, was awarded on July 3, 2006. Furthermore, 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. No stock options were granted to Directors in 2006. For a discussion of the Company's policies regarding issuance of stock options and restricted stock grants, see "Executive Compensation-Compensation Discussion and Analysis-Certain Policies of Executive Compensation Program" below.

In addition, the chairmen of the Board's standing committees (Audit, Compensation and Corporate Governance/Nominating) each spend a significant amount of extra time beyond what is required for Board committee membership in performing their duties. In acknowledgment of this fact, the chairmen of each standing committee receive the following additional annual retainers, payable in cash in arrears:

Audit Committee Chairman	$10,000
Compensation Committee Chairman	$ 5,000
Corporate Governance/Nominating Committee Chairman	$ 5,000

Board and Board Committee Meeting Fees

Each non-employee Director receives $1,500 cash for in-person attendance at a meeting of the Board of Directors ($500 if such attendance is telephonic) and $1,500 cash for each meeting of a standing committee of the Board of Directors attended ($500 if telephonic). Board and Board committee meeting fees are paid in cash to the Directors at or shortly after the time of the respective meetings. The Board also appoints non-employee Directors to other special committees of the Board, as necessary. Examples of these special committees may include, but are not limited to, a Pricing Committee and a Dividend Committee for our Preferred Stock. Currently we do not pay committee meeting fees to non-employee Directors for attendance at special committee meetings.

The following 2006 Director Compensation Table shown below reflects information regarding the compensation of each of the non-employee Directors with respect to 2006.

2006 Director Compensation

Name(1)	Fees Earned or Paid in Cash(2)	Stock Awards ($)(3)	Total
Thurmon M. Andress	$ 44,500	$ 71,802	$116,302
Vincent S. Andrews	$ 35,500	$ 71,802	$107,302
Jonathan M. Clarkson	$ 38,500	$ 49,994	$ 88,494
Michael A. Creel	$ 37,500	$ 49,994	$ 87,494
Stanley S. Raphael	$ 31,000	$ 71,802	$102,802
John Sfondrini	$ 31,000	$ 71,802	$102,802
Robert W. Shower	$ 49,500	$ 71,802	$121,302
David F. Work	$ 41,000	$ 71,802	$112,802

(1) John W. Elias, the Company's President, Chairman of the Board and Chief Executive Officer, is not included in this table, as he is an employee of the Company and receives no compensation for his service as a Director. The compensation received by Mr. Elias as an employee of the Company is shown on the Summary Compensation Table on page 27.

(2) Reflects the portion of the Board annual retainer that was paid in cash in 2006 ($20,000), committee chairmanship annual retainers paid in cash on June 7, 2006 (Mr. Andress, $5,000; Mr. Shower, $10,000; and Mr. Work, $5,000) and the Board and Board committee meeting fees paid in 2006.

(3) Reflects the dollar amount recognized for financial statement reporting purposes for the fiscal year ended December 31, 2006 in accordance with Financial Accounting Standards Board Statement of Financial Accounting Standards No. 123(R) ("FAS 123R"), and thus includes amounts in respect of stock awards granted in and prior to 2006. Pursuant to SEC rules, the amounts shown exclude the impact of estimated forfeitures. A discussion of the assumptions used in calculating these amounts may be found in Note 17 to our 2006 audited financial statements included in our annual report on Form 10-K for the year ended December 31, 2006. These amounts reflect the Company's accounting expense for these awards and do not correspond to the actual value that may be recognized by directors. On July 3, 2006, each director received a stock grant for 2,511 shares of Common Stock, with a fair market value on the grant date of $49,994 (based upon an average of high and low stock price on the grant date of $19.91). This stock grant was immediately vested. As of December 31, 2006, each Director held the following aggregate number of shares of unvested stock previously awarded under restricted stock grants: Mr. Andress: 2,470 shares; Mr. Andrews: 2,470 shares; Mr. Raphael: 2,470 shares; Mr. Sfondrini: 2,470 shares; Mr. Shower: 2,470 shares; and Mr. Work: 2,470 shares. Messrs. Clarkson and Creel have not received any stock grants for which amounts remained unvested at December 31, 2006. No dollar amounts were recognized in 2006 under FAS 123R with respect to option grants to non-employee Directors. As of December 31, 2006, the number of outstanding option awards held by the named directors were as follows: Mr. Andress: 8,000 shares; Mr. Andrews: 21,300 shares; Mr. Raphael: 21,300 shares; and Mr. Work: 8,000 shares.

Stock Ownership Requirements for Directors

At their March 9, 2006 meeting, the Corporate Governance/Nominating Committee recommended that each Director be required to own shares of common stock of the Company equal to three times their annual Director compensation for 2006 and that such ownership be achieved within three years from July 1, 2006. "Stock ownership" is defined to include stock owned by the Director directly or indirectly, stock owned by a controlled entity, such as an IRA or trust that is controlled by the Director, and restricted stock that has not yet vested but will vest to the Director prior to July 1, 2009. Director compensation includes the annual retainer (both cash and stock), committee chairmanship fees and Board and committee meeting fees. The Committee monitors each Director's progress over time towards his or her three-year target and informs the Directors of their progress towards this target annually.

EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Overview of Compensation Program

The Compensation Committee, composed of Messrs. Andress (Chairman), Clarkson, Shower and Work, is responsible for reviewing and implementing the Company's executive compensation program. The role of the Committee is to oversee our compensation and benefit plans and policies, administer the Incentive Plan (including reviewing and approving equity grants to executive officers) and review and approve annually all compensation decisions relating to the Chairman and CEO, the Chief Financial Officer and the other executive officer named in the Summary Compensation Table on page 27 (the "executive officers"). The Committee submits its decisions regarding compensation for the executive officers to the Non-Employee Directors of the Board for ratification.

Philosophy and Objectives of the Executive Compensation Policy

The Compensation Committee, in establishing the components and levels of compensation for its executive officers, seeks:

- to enable us to attract and retain highly qualified executives in key positions and ensure that compensation paid to key employees remains competitive relative to the compensation paid to similarly situated executives of peer companies;
- to provide compensation to the executive officers that both they and the stockholders perceive as fair and equitable;
- to provide financial incentives in the form of cash bonuses and equity compensation in order to align the interests of executive officers more closely with those of the stockholders of the Company;
- to reward performance as measured against established objectives and goals; and
- to motivate our executives to increase stockholder value by improving corporate performance and profitability.

Fundamentally, we have in large part a pay-for-performance, at-risk compensation philosophy, and our short and long-term incentive compensation programs provide enough flexibility for the Committee to appropriately reward our executive officers when it believes the Company's overall performance, as well as the executives' performances, justify doing so. When our operating and financial performances exceed expectations, the potential for significant rewards exists. The Committee believes that compensation should also be structured to ensure that a significant portion will be at risk—that is, it will generally be earned or increased only when the Company overall or the executive officers are successful in ways that are aligned with and support stockholder interests. We believe that this overall approach to executive compensation should be perceived as fair and equitable to both the executive officer and the stockholders.

Historically, and in fiscal 2006, we granted a significant portion of total compensation to our executive officers in the form of incentive compensation that is at-risk. For the fiscal year ended 2006, at-risk compensation, including the performance-based cash bonus awards and the grants of restricted stock, constituted the following percentages of each executive officer's total compensation package:

Executive Officer	Percentage of Total Compensation Received from 2006 Base Salary and Other Benefits(1)(3)	Percentage of Total Compensation received from At-Risk 2006 Compensation(2)(3)
John W. Elias	54%	46%
John O. Tugwell	27%	73%
Michael G. Long	26%	74%

(1) This percentage is based upon amounts received by the executive officers from base salary and the amounts set forth under "All Other Compensation" in the Summary Compensation Table appearing later in this proxy statement.
(2) This percentage is based upon amounts received by the executive officers from the 2006 performance-based annual bonus awards and the grant date value of restricted stock granted in 2006 described below. The percentage reflected above includes any performance-based bonus awards paid on or about April 1, 2007 for 2006 performance and all restricted stock grants awarded in 2006. It does not include the restricted stock grants awarded on April 1, 2007.
(3) The percentages in this table are based on the market value of stock grants on the grant date, unlike the Summary Compensation Table where value of stock grants are based upon FAS 123R expense; therefore, the percentages vary from those that would be obtained by using the values shown in the Summary Compensation Table.

In establishing stock and bonus award levels, we generally do not consider the equity ownership levels of the executive officers or prior awards that are fully vested. It is our belief that competitors who might try to hire away these employees would not give credit for equity ownership in the Company. Accordingly, to remain competitive we believe that we cannot afford to give credit to that factor either.

There is no pre-established policy or formula that controls our compensation decisions including the allocation between cash and non-cash or short-term and long-term incentive compensation. Rather, the Committee seeks to create what they believe is the most appropriate allocation among the compensation components described below in "—2006 Executive Compensation Components." When setting the executive officers' compensation, the Committee reviews information provided by the Mercer Energy Company Compensation Survey (the "Mercer Survey") or other benchmark data derived from information reported in publicly-available proxy statements or other sources. The Mercer Survey is produced by an independent consultant that surveys and compiles annual energy sector compensation information, including salaries, bonuses and long-term equity-based awards, and, for its 2006 survey, contains information gathered from over 184 companies in the energy sector. The peer companies utilized in the Mercer Survey are not predetermined by us and are broken down into categories according to industry segment, geographic area and annual revenues and sales. The peer companies' annual revenue and sales range from less than $100 million to $1.2 billion or more. We generally compare ourselves to the data applicable to companies in the $100 million to $700 million range in annual revenues and sales. We feel that in attracting and retaining well-qualified and talented employees, we are competing against companies both inside and outside the exploration and production segment of the oil and gas industry, so we do not restrict our review to only the exploration and production category of energy companies. The independent compensation consultant does not receive compensation from the Company other than a fee of less than $2,000 to provide the annual compensation survey information, and the consultant does not attend the Committee meetings. The Company, at the request of the Compensation Committee, purchases the Mercer Survey to assist the Committee in its review of salaries, bonuses and equity-based awards. The Committee does not retain a separate outside advisor or purchase any other compensation survey or report that is specifically for executive compensation, although it does, on occasion, consider other benchmark data derived from other public and private sources. While the Committee takes into consideration the Mercer Survey and other benchmark data, that information is just one factor considered by the Committee and the Committee does not adhere to any rigid guidelines regarding the use of benchmarks.

In addition to reviewing market analyses of pay levels and considering individual performance related to each executive officer, the Committee considers the total compensation of each executive officer relative to each other executive officer and relative to other members of the management team. All employees, including the executive officers, are assigned to pay grades, determined by comparing position-specific duties and responsibilities. Each pay grade has a salary range with corresponding annual and long-term incentive award opportunities. The pay grades range from 6 to 22. Executive officers fall in grades 18 and above. Although Mr. Elias' position falls in grade 22, the Committee, with which Mr. Elias concurred, had determined that for compensation purposes, he will be treated as if he were a grade 21 pay level. Compensation paid to an employee generally must be within the parameters for his or her pay grade. We feel this approach insures more consistent compensation opportunities for members of management with similar duties and responsibilities.

In the case of Mr. Elias, his compensation is also determined in part by the terms of his employment agreement, which is discussed in more detail below under "—Other Benefits-*Employment Agreements*." His agreement provides for a minimum base salary of $350,000, that his base salary may be increased, but not decreased, and minimal annual bonus plan opportunities of at least 50% of base salary for target performance and at least 100% of base salary at the maximum performance level.

Role of Executive Officers in Compensation Decisions

Equity awards, as well as bonuses and changes in salaries for all employees, including the executive officers, are individually determined and administered by the Compensation Committee and ratified by the non-employee Directors, in the case of the other executive officers, taking into account recommendations from the Chief Executive Officer. The Chief Executive Officer assists the Compensation Committee by:

- preparing agendas for the meetings of the Compensation Committee;
- annually reviewing each of the other executive officer's performance with the Committee, as well as other key employees;
- recommending salary rate ranges and bonus target opportunities for the other executive officers and employees;
- recommending salary, bonus and long-term incentive (stock) awards for other executive officers and employees; and
- attending Compensation Committee meetings, except during executive session.

The Chief Executive Officer's participation is meant to provide the Compensation Committee with input regarding the Company's compensation philosophy, process and decisions, but all compensation decisions are made by the Committee and submitted to the non-employee Directors for ratification. In addition to providing factual information as described above, Mr. Elias articulates management's views on current compensation programs and processes, recommends relevant performance measures to be used for future awards and otherwise supplies information to assist the Committee. The Compensation Committee meets outside the presence of all executive officers when analyzing the Chief Executive Officer's performance and considering his compensation. The Human Resources Department of the Company also supports the Committee in its work in determining competitive compensation levels, including for executives, analyzing data regarding compensation levels and programs specific to peer-group companies in the energy business as provided by the Mercer Survey.

2006 Executive Compensation Components

For the fiscal year ended December 31, 2006, the principal components of compensation for the executive officers, as well as other employees, were:

- Base Salary
- Performance-Based Cash Bonus
- Long-Term Equity-Based Compensation
- 401(k) Employee Savings Plan
- Health and Welfare Benefits, such as medical, dental, vision care, disability insurance, and life insurance
- Severance Benefits under Change of Control Agreements

Each of these components is discussed in greater detail below, along with a description of our philosophy on achieving an appropriate balance between the same.

Base Salary. Base salaries of the executive officers (including that set forth in Mr. Elias' employment agreement as described below under "—Other Benefits-*Employment Agreements*") are determined based on the

Compensation Committee's review of a number of factors, including comparable industry data contained in the Mercer Survey and individual factors such as an executive's specific responsibilities, experience, individual performance and growth potential. In the case of the executive officers other than the Chief Executive Officer, the Committee also considers his recommendations. Based on these factors, the Committee establishes base salary rate ranges for each position that fall within the salary ranges established for individual pay grades, as discussed above in "—Philosophy and Objectives of the Executive Compensation Policy." The Compensation Committee's salary recommendations are subject to ratification by the full Board. The base salary ranges were not changed for any of the executive officer positions in 2006. At their January 2007 meeting, after reviewing the Mercer Survey and other studies of energy company salaries, the Committee recommended a 5% increase to the salary rate ranges for all pay grades, including those of executive officers. The salaries are reviewed on an annual basis, as well as at the time of a promotion or other change in responsibilities. Increases in salary are generally based on an evaluation of the individual's performance and level of pay compared to the peer-group companies, and can include merit increases or cost-of-living increases, or a combination of both. As discussed below in "—Other Benefits-*Employment Agreements*," Mr. Elias' employment agreement requires the Compensation Committee to annually review his base salary and make a recommendation to the Board of Directors regarding possible increases. Under the terms of Mr. Elias' employment agreement, the Board of Directors may, in its sole discretion, increase, but not decrease, his base salary. In general, executive officers and other employees of the Company are reviewed for potential salary increases on or about April 1 of each year, although some salary increases were granted effective October 1, 2006, as discussed below.

As part of the Committee's annual compensation review procedure, effective as of April 1, 2006, Mr. Tugwell, the Company's Chief Operating Officer, received a base salary increase from $205,000 to $220,000, and Mr. Long, the Company's Chief Financial Officer, received a base salary increase from $200,000 to $212,000. Such increases were based on 2005 performance and salary information provided in the Mercer Survey. In addition, at the Compensation Committee's August 25, 2006 meeting, the Committee approved increases in base salary, to be effective as of October 1, 2006, for Mr. Tugwell to $235,000 and for Mr. Long to $227,000. The Committee based its approval of these increases in base salaries upon general competitive compensation levels, based on the Mercer Survey, and industry conditions. The combined 2006 increases reflect a 14.6% increase in Mr. Tugwell's salary from December 31, 2005 to December 31, 2006, and a 13.5% increase in Mr. Long's salary for the same time period. While the Compensation Committee recommended to the non-employee Directors of the Board during the annual compensation review procedure that Mr. Elias receive an increase in base salary in April 2006, Mr. Elias declined to accept any increase in base salary even though the Company's prior year performance had been positive. At this point in time, Mr. Elias felt that his salary for 2006 was competitive for comparable-sized companies.

At their March 2007 meeting, the Committee approved base salary increases as follows: Mr. Elias' salary was increased from $350,000, the minimum salary provided for under his employment agreement, to $400,000; Mr. Tugwell's base salary was increased to $246,000; and Mr. Long's base salary was increased to $238,000. These increases were based on individual performance and competitive salary information provided in the Mercer Survey and other sources.

Performance-Based Cash Bonus. The Company also offers each of its executive officers an opportunity to earn additional cash compensation in the form of annual cash bonuses following attainment of specified Company performance objectives established by the Committee and certain individual performance objectives established at the beginning of the year. The Committee believes that making a significant portion of executive officer compensation subject to the Company attaining specified performance objectives and strategic goals and the individual meeting certain individual objectives motivates the executive officers to increase their respective individual efforts on behalf of the Company. The Committee believes that it is appropriate that the Company's executive officers' compensation be more heavily weighted as to whether the Company attains its specified performance objectives and strategic goals and less dependent on the executive's attainment of individual goals. For pay grades lower than 15, which does not include executive officers, the Company's performance is weighted less heavily, and the individual's performance is weighted more heavily. The objectives and goals are specifically set to be challenging, yet achievable, with strong performance from the executive officers and the employees of the Company as a whole.

Under the Company's bonus program, the Compensation Committee uses discretion in determining each executive officer's annual bonus, after reviewing the Company performance objectives, individual performance objectives, overall financial and operational performance of the Company, compensation survey data and recommendations of the Chief Executive Officer with respect to the other executive officers. These determinations are submitted to the non-employee Directors for ratification. The amount of bonus that may be earned is based on a targeted percentage of the individual's annual salary, subject to a maximum-targeted percentage, and is subject to adjustment by the Committee. Total bonus opportunities for 2006 for Mr. Tugwell ranged from 0% to 120% of base salary, with a target payout of 60%; for Mr. Long from 0% to 110% of base salary, with a target payout of 55%; and for Mr. Elias from 0% to 130% of base salary, with a target payout of 65%. The bonuses of the executive officers for 2006 performance were based 80% on Company performance and 20% on achievement of the individual's performance objectives.

Company Performance. The Company performance component of the bonus is based on:

- achievement of performance objectives as established by the Committee,
- subject to adjustment at the discretion of the Committee based achievement of overall Company financial goals.

The Company performance objectives for 2006 consisted of:

- specified annual increases in reserves (weighted 40%);
- specified annual increases in production (weighted 30%);
- competitive finding and development costs ("F&D") (weighted 15%);
- lease operating expense ("LOE") (weighted 7.5%); and
- control of general and administrative expenses ("G&A") (weighted 7.5%).

The Committee establishes the Company performance objectives annually based on those projected in the Company's annual budget and plan, as revised, for the applicable period, approved by management and reviewed and ratified by the Board of Directors. The target levels for performance objectives may differ from the budget and plan in a given year, but are intended to reflect planned performance over the course of a full annual business cycle. Accordingly, the target levels for the performance objectives are established with the expectation of paying bonuses out approximately at target, with a low probability of either failing to reach the minimum threshold level or reaching the maximum level. Both the LOE and G&A measures are calculated on a unit-of-production basis. G&A excludes capitalized costs, restricted stock grants and FIN 44 requirements. In addition, the F&D objective is calculated as a three-year moving average obtained by dividing capital expenditures by new reserves net of revisions without including acquisitions. This is the only category of the performance objectives where acquisitions are excluded. The objectives for reserve growth, production growth and competitive F&D costs are the major components of the Company's bonus program.

The bonus components described above are based generally upon specific performance criteria for each component. Payouts range from 0% to 200% of target bonuses. The minimum threshold performance to begin earning a payout for each component for 2006 performance is listed below. Payout is prorated based on actual performance, subject to a maximum payout level of 200%.

- Reserve Growth – 5.0% or greater
- Production Growth – 3.5% or greater
- Finding & Development Costs (3-year moving average) – $2.71 per Mcfe or less
- Lease Operating Costs – $0.61 per Mcfe or less
- G&A Expenses – $0.64 per Mcfe or less

For 2006, the Company did not achieve its minimum thresholds to earn a payout in the areas of reserve growth, F&D costs and G&A expense. Production growth was slightly above the minimum threshold required to earn a payout but well below expectations. LOE expense was significantly better than the minimum threshold required to earn a payout. However it was the Committee's judgment, with which Mr. Elias concurred, that no bonus would be payable with regard to any of the Company performance objectives for the reasons discussed below.

Overall Financial Goals. With respect to the bonus for the executive officers, the Committee considers, but does not rely solely on, the above predetermined formulas when evaluating achievement of the Company's performance objectives. In this respect, the Committee also considers whether the Company was successful in meeting its overall financial goals. This is a subjective assessment, with no particular weighting given, but this objective is considered by the Committee in determining executive officer bonuses. The financial goals for the Company for 2006 were:

- to ensure that funds are available to execute the Company's overall recommended capital expenditure program as projected in its 2006 approved budget and plan while maintaining a prudent financial structure with a debt-to-total-capital ratio of less than 30% (however, it is recognized that from time to time this ratio will be exceeded due to acquisitions);
- to fund the approved capital expenditure program, excluding acquisitions, from internal cash flow rather than taking on additional debt;
- building pre-tax cash flow from 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.

The Committee, in its judgment, recognized that the Company was able to maintain a relatively conservative balance sheet when measured against these overall financial goals. Nevertheless, the Committee found that:

- The Company exceeded its debt-to-total-capital ratio of 30% as was expected because of two year-end acquisitions that were funded with debt. However, management expects to bring the fiscal year-end debt-to-total-capital ratio to a lower level by year-end 2007;
- The Company borrowed approximately $2 million to fund its capital spending program (excluding acquisitions) because cash flow was slightly less than expected for the full year; and
- Natural gas prices fell throughout the year, causing the Company to record a non-cash ceiling test write-down of $96.9 million, pre-tax in the third quarter. The falling gas prices and lower-than-expected production volumes reduced cash flow below the Company's pre-acquisition capital spending, resulting in an increase in debt, as compared with the reduction in debt we originally expected.

Still, the Company was able to close two acquisitions utilizing its unused borrowing capacity. The larger of the two acquisitions, Chapman Ranch, was deemed critical to the Company's ability to gain control over the development and exploration of this attractive asset. In addition to the acquisitions closed at the end of 2006, the Company was able to negotiate a potentially transforming acquisition of properties owned by Smith Production Inc. in south and southeast Texas, which closed late in January 2007. We view this acquisition as a company-transforming event providing a step change in reserve and production growth, while exposing the Company to a wide array of new development and exploration opportunities. However, on balance for all the above reasons, at their March 2007 meeting, the

Compensation Committee recommended that no bonus payout of the Company performance portion of the bonus program be made for 2006 performance for all employees, including the executive officers.

Individual Performance. In evaluating an executive officer's performance towards his or her individual objectives (weighted at 20% of total bonus target), the Compensation Committee uses its discretion and assesses performance by the executive officer against mutually defined expectations. The process includes individual appraisal components that are both objective and subjective. This includes an assessment of how the executive performed relative to defined roles and accountabilities, quantifiable objectives such as meeting the Company's specific fiscal or physical targets, overall performance of the Company, and a more subjective assessment of a number of performance attributes such as teamwork, communication, participation leadership, decision making, creativity/innovation, planning and organization and performance management. With regard to individual objectives, there are no specific formulas. The Committee makes an assessment, in its judgment, of the degree to which individual objectives have been satisfied. 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.

In the case of Messrs. Long and Tugwell, as part of their individual objectives, they are expected to ensure that attractive investment opportunities are identified on an ongoing basis and ultimately added to the company's portfolio in order to provide opportunities for future growth. These opportunities can take on many forms such as seismic options, new acreage leases, farm-ins and/or farm-outs, joint exploration ventures, and acquisitions of producing properties that have upside potential. In doing so, Messrs. Long and Tugwell are expected to apply the most appropriate technology in an effective manner while ensuring that constant attention is given to managing cost effectively. The Company's total expenses (i.e. LOE, production and ad valorem taxes, G&A and net interest and dividends) on a dollar per unit-of-production basis are expected to be in the lowest quartile of our peer group. They are expected to make intelligent and timely hedging decisions to help mitigate the adverse impact commodity price volatility can have on cash flow and the Company's ability to continue expanding its program. Messrs. Long and Tugwell also have essentially the same roles and accountabilities as Mr. Elias, as discussed below, except they are applicable to their specified functional areas of responsibilities. Messrs. Long and Tugwell generally exceeded expectations on the above and have played very important roles in positioning the Company for potentially significant physical and fiscal growth in 2007 and beyond.

For the reasons discussed above, at their March 2007 meeting, the Compensation Committee recommended to the Board of Directors that no payout of the Company portion (80%) of the bonus program be made for Messrs. Tugwell and Long for 2006. However, the Committee also acknowledged the strong individual performance of Messrs. Tugwell and Long, including their extraordinary effort (and similar efforts by many of the Company's employees) in the fourth quarter 2006 and first quarter 2007 acquisition of properties from Smith Production, Inc., and determined that those efforts be emphasized in determining the individual component (20%) of their final bonus awards for fiscal 2006 and that the full amount of potential bonus payment be made under this component. Accordingly, at their March 2007 meeting, the Compensation Committee approved, and the Board of Directors ratified, cash bonus awards be made to these executive officers based upon the officer's individual performance at the maximum rate permitted, as follows: Mr. Tugwell was awarded $56,000 and Mr. Long was awarded $49,900. These bonuses were paid on or about April 1, 2007 and represent 24% and 22% of Messrs. Tugwell's and Long's base salary, respectively.

With respect to Mr. Elias, the 20% of his bonus based on individual performance is based on achievement of individual roles and accountabilities, achievement of short-term objectives and progress toward achievement of long-term goals. The roles and accountabilities for Mr. Elias included:

- Providing overall leadership for all aspects of the Company;
- Overseeing, developing and implementing the Company's budget, plan, objectives and goals;
- Monitoring and directing progress in achieving the Company's budget, plan, objectives and goals;
- Ensuring legitimate interests of the Board, shareholders, management and others are considered;

- Reviewing and approving operating, financial and personnel matters; and
- Building and maintaining an industry network in order to help achieve the Company's goals and objectives.

The short-term individual objectives for Mr. Elias included:

- achieving a consistent pattern of reserve growth at a competitive finding and development cost;
- achieving a consistent pattern of production increases in a cost-effective manner;
- maintaining a prudent financial structure that provides the flexibility to effectively execute the Company's business plan (a debt-to-total capital of less than 30% and internal cash flow sufficient to fund the Company's desired program);
- expanding and/or increasing the Company's reserve base and production via an acquisition or merger that is not detrimental to the Company's financial structure; and
- expanding and/or increasing the Company's reserve base and production in the immediate and longer-term through organic growth in new grass root exploration and/or exploitation plays.

In addition, during 2006 the Committee and Mr. Elias focused on certain longer term (three-year) goals for the Company. Specifically, the Compensation Committee and Mr. Elias agreed on the following long-term goals for the Company:

- growing year-end reserves to the range of 200 to 250 Bcfe by year-end 2008;
- obtaining a reserve-to-production (R/P) ratio of 10 years by year-end 2008; and
- growing annual production to the range of 20 to 25 Bcfe by year-end 2008 (which represents a sustained producing rate of 54.8 to 68.5 MMcfe per day).

These three-year goals and other goals and targets described herein are aspirational in nature and are forward-looking statements. We cannot assure you that they will be achieved and actual outcomes may vary materially. These goals involve risks and uncertainties, including, but not limited to, those set forth under *ITEM 1A. "RISK FACTORS"* and other factors detailed in our Annual Report on Form 10-K and our other filings with the Securities and Exchange Commission. We feel that the Chapman Ranch acquisition completed at the end of 2006 and the Smith Production, Inc. acquisition completed in January of 2007 have resulted in an increased likelihood of our being able to achieve, at least to some extent, these long-term goals earlier than originally envisioned. On purely a pro forma basis for year-end 2006, with the Smith acquisition the Company's proven reserves would be approximately 225 Bcfe, annual production would be 23.4 Bcfe and a reserve-to-production ratio of almost 9 years. The Committee and Mr. Elias agreed that the above longer term goals are to be achieved on a cost-effective basis and not at the expense of the long-term viability of the Company.

As noted above, it was the judgment of the Compensation Committee that the Company did not achieve the target performance levels of reserve growth, production and finding and development cost set out in the 2006 approved budget and plan. However, Mr. Elias did provide the required leadership that resulted in a successful acquisition of assets that significantly increased the Company's proven reserves, production, prospects and undeveloped acreage inventory. This transforming transaction has greatly enhanced the ability of the Company to achieve some of its long-term strategic goals sooner than had been originally envisioned and, also, provides a new platform from which the Company expects to grow.

In spite of the transforming transaction that was the focus of much of Mr. Elias' efforts in 2006, the Committee felt that the 2006 operating and financial results should be the major components used to determine whether Mr. Elias should earn an annual bonus award for 2006 individual performance. Therefore, after review of all performance factors, it was the judgment of the Compensation Committee and Mr. Elias that no bonus award for 2006 would be made for Mr.

Elias for the individual component, and the non-employee Directors of the Board ratified this decision at their March 2007 meeting.

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 past, in the case of Mr. Elias, outside of the Incentive Plan, to provide long-term incentive-based compensation. All equity grants made in 2006 were pursuant to the Incentive Plan.

In recent years, we have relied primarily on restricted stock, as opposed to stock option, awards. A restricted stock award is a grant of a right to receive shares that vest over time. As the stock award vests, the shares are owned outright. Such awards are made at the discretion of the Compensation Committee and are ratified by the non-employee Directors. Relevant factors in the determination of grants, which are not subject to any particular weighting, are

- the impact the executive's performance had on the Company and what impact the executive is expected to have in the future;
- the desire to retain the executive in the employee of the Company;
- data regarding stock grants at comparable companies, including the Mercer Survey;
- the relative grade level of the officers;
- length of service with the Company;
- the executive officers' base salary;
- in the case of other executive officers, recommendations of the Chief Executive Officer; and
- performance evaluation of each executive officer with respect to the prior fiscal year.

Awards of restricted stock 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.

Historically, we awarded restricted stock that vested and was issued in equal one-third increments on the first, second and third anniversary of the date of grant. However, the Compensation Committee and the Board of Directors have determined that restricted stock grants, beginning with those made in October 2006 as discussed below, should vest over a longer period of time than previous grants. We feel that a longer vesting schedule not only more closely aligns the executives' (and other employees') interests with those of the stockholders, it also encourages retention of highly qualified and talented employees whose abilities help the Company achieve its long-term goals. Accordingly, since August 2006, the Company has shifted to awarding restricted stock that vests 20% on the second anniversary of the grant date and vests 40% on each of the third and fourth anniversaries of the grant date.

At their March 2006 meeting, the Compensation Committee approved, and the non-employee Directors of the Board ratified, restricted stock grants to Messrs. Elias, Tugwell and Long in the amounts of 12,000 shares, 5,400 shares and 5,400 shares, respectively. The grant date for this award was April 1, 2006. These restricted stock grants, as well as previously awarded restricted stock held by executive officers, vests and shares are issued in equal one-third increments on the first, second and third anniversary of the date of grant.

At its meeting held on August 25, 2006, the Compensation Committee of the Company, in recognition of the officers' performance and the competitive compensation market and other industry conditions, approved a supplemental, one-time restricted stock grant to each of Messrs. Tugwell and Long in the amount of 30,000 shares of common stock, effective October 1, 2006. These one-time grants vested over the longer period described above. The Compensation Committee based its approval of these awards upon general competitive compensation levels and industry conditions. In determining the competitive compensation levels, the Committee analyzed information regarding compensation levels and programs in the energy sector. Mr. Elias did not receive a supplemental one-time restricted stock grant at that time.

The restricted stock awards made to executive officers in 2006 are set forth in the table below. The value of the awards, based on the stock price at the date of grant date ranged from 60% to 232% of base salary depending on the officer's position and base salary at the time of the grant.

Name	Award Date of Grant	Number of Shares of Stock Granted	Grant Date Fair Market Value	Stock Grants as Percent of Base Salary
Mr. Elias.............	04/01/2006	12,000	$ 306,840	88%
Mr. Tugwell.........	04/01/2006	5,400	$ 122,161	60%
	10/01/2006	30,000	$ 404,427	224%
Mr. Long	04/01/2006	5,400	$ 122,161	69%
	10/01/2006	30,000	$ 404,427	232%

At their March 2007 meeting, the Compensation Committee approved restricted stock grants for Messrs. Elias, Tugwell and Long in the amounts of 20,000 shares, 10,000 shares and 10,000 shares, respectively. The grant date for this award was April 1, 2007. These restricted stock grants will vest 20% after two years (April 1, 2009) and 40% on each of the third and fourth anniversary dates of the grant date (April 1, 2010 and 2011).

Grants of stock options to executive officers may be made by the Compensation Committee although none have been granted since 2003 except for a grant to Mr. Elias in 2004 pursuant to the terms of his employment agreement. At December 31, 2006, options under the Incentive Plan had been granted to 56 current and former employees and Directors, at exercise prices ranging from $2.11 per share to $13.99 per share. For a discussion of the Company's philosophy on its shift away from granting stock options to employees, including the executive officers, in favor of awarding restricted stock grants, see "—Certain Policies of Executive Compensation Program-*Company Shift Away from Issuing Stock Options in Favor of Restricted Stock Grants*" below.

Other Benefits

The Company provides a competitive benefits package to all full-time employees, which includes health and welfare benefits, such as medical, dental, vision care, disability insurance, life insurance benefits, a 401(k) savings plan, and severance benefits under change in control agreements. The Company has no executive perquisite benefits (e.g. club memberships or company vehicles) for any executive officers with an incremental cost to the Company in excess of $10,000, and does not provide any deferred compensation programs or supplemental pensions to any employees, including the executive officers. The Company does provide supplemental life insurance for Mr. Elias, in accordance with his employment agreement, the cost of which is reflected in the "Summary Compensation Table" below.

401(k) 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 $15,500 for the current year (subject to certain limitations and exceptions 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, in 2006 the Company elected to match 100% 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. The Company contributions to the executive officers, except in the case of Mr. Elias, as he does not participate in the 401(k) Plan, are shown below on the Summary Compensation Table.

Change in Control Severance Agreements. The Company has entered into a severance agreement with each employee of the Company, including the executive officers. These agreements grant severance benefits in the event of a qualified termination of employment within two years of a change of control. The oil and gas industry is constantly evolving and changing, including through acquisitions and mergers. The Company has chosen to enter into change of control agreements with all of its employees, including the executive officers, to promote stability and continuity of management and personnel. The Company feels that by protecting employees from any potential economic upheaval in their personal lives at the time of a change in control, employees will be better able to focus on the work at hand. The severance agreements executed by the executive officers are "double trigger" agreements, not "single trigger." In other words, benefits are payable following a change of control only if the executive is terminated without cause or resigns for good reason. The Company feels that linking severance benefits to a change of control will eliminate, or at least reduce, any reluctance of senior management to pursue potential change in control transactions that may be in the best interests of the stockholders. Information regarding applicable payments and other benefits under such agreements for the executive officers is provided under the heading "—Potential Payments Upon Change in Control or Termination" below. In the case of Mr. Elias, if a qualified termination of employment occurs within two years of a change in control, he is entitled to the benefits under his change in control severance agreement, but not under his employment agreement described below.

Employment Agreements. In addition to the components of executive compensation described above, Mr. Elias is a party to an employment agreement dated effective November 16, 1998 with the Company, which agreement 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. The Company entered into an employment agreement with Mr. Elias in order to induce and retain the employment of Mr. Elias and to stimulate his active interest in the development and financial success of the Company and the term of the agreement was designed to give the Company the ability to retain Mr. Elias' services until his retirement. The Employment Agreement had an initial term of three years from January 1, 1999, and is extended automatically for successive one-year periods on each anniversary of the effective date unless terminated by either Mr. Elias or the Company. Most recently, the agreement renewed through November 16, 2007, based on largely the same considerations.

The employment contract of Mr. Elias provided for an initial minimum salary of $350,000, and 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 on or about April 1 of each year 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 base salary. As discussed above under "—2006 Executive Compensation Components-*Base Salary*," no salary increase was recommended by the Committee or awarded by the Board for Mr. Elias during 2006 but he did receive a base salary increase of $50,000 in 2007. Mr. Elias' employment agreement also provides that he have annual bonus plan opportunities of at least 50% of base salary for target performance and at least 100% of base salary at the maximum performance level. His employment agreement also provided for awards of non-qualified stock options in the past, the final grant being 50,000 shares on April 1, 2004. No further stock options will be granted under his employment agreement. Mr. Elias is the only employee with which the Company has entered into an employment agreement. Mr. Elias' employment agreement also entitles him to certain benefits upon a termination of employment. See "—Potential Payments Upon Change in Control or Termination" below for information about the potential payments and benefits to Mr. Elias upon termination of his employment with the Company.

Other Paid Time-Off Benefits. The Company provides vacation and other paid holidays to all employees, including the named officers, which are comparable to those provided at other companies in a similar industry.

Certain Policies of Executive Compensation Program

Timing of Equity-Based Compensation. Stock option grants and restricted stock grants are effective as of the grant date, and options are priced at "fair market value" on the date of the grant. The Incentive Plan defines "fair market value" as the mean between the high and low price of the Company's stock on the grant date or, if the grant date is not a day when the stock market is open, the last preceding date for which trading data is reported by the market. Equity grants are only made to executive officers during the normal annual compensation-setting cycle (on or about April 1 of each year) except under circumstances discussed under the heading "—*Exceptions to Usual Procedures*" below and except in the case of new hires that begin employment outside the time of the annual compensation-setting cycle.

Company Shift Away from Granting Stock Options In Favor of Restricted Stock Grants. In the last three years, the Compensation Committee has approved the award of restricted stock instead of stock 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; and
- restricted stock, as opposed to stock options, more closely aligns the interests of the executive officers and other employees with those of the stockholders in seeking consistent long-term performance of the Company.

Exceptions to Usual Procedures. The Compensation Committee may from time to time approve (subject to ratification by the Board) the payment of special cash compensation or the grant of special equity-based awards to one or more of the executive officers, as it did in August 2006, in addition to payments and grants approved during the normal annual compensation-setting cycle. The Committee might make such a recommendation if it believes it would be appropriate to reward one or more executive officers in recognition of contributions to a particular project, or in response to competitive and other factors that were not addressed during the normal annual compensation-setting cycle. The Committee may also recommend adjustments to the annual performance-based objectives to take into consideration extraordinary, unusual or other occurrences that may happen during a fiscal year that cause the Committee and the Board to conclude that the measure or measures as so established do not in fact achieve the Company's overall intended goals.

At their August 2006 meeting, the Compensation Committee approved a change to the annual review procedure for executive officers, determining that the executive officers will generally continue to be reviewed for potential salary increases on or about April 1, when the other employees and officers of the Company are also reviewed, but that any salary increases for the executive officers would not be effective until October 1 of the year they are approved. However, at their March 2007 meeting, the Committee decided that this policy may not be in the best interests of the Company because it is not administratively effective, and suspended implementation of the policy for salary increases approved in March 2007, which will be effective on April 1, 2007. The April 1, 2007 salary increases were adjusted on a pro rata basis to take into account the previous salary increases that were effective as of October 1, 2006.

Overriding Royalty Interests. 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.

Security Ownership Requirement for Executive Officers. The Company has not established any formal policies or guidelines addressing expected levels of stock ownership for the executive officers. However, the Company does have a stock ownership requirement for its non-employee Directors, as described above in "Director Compensation–Stock Ownership Requirements for Directors" above.

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. Option 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). In addition, restricted stock awards that vest solely on the basis of the passage of time are not considered performance-based compensation under Section 162(m), so compensation realized upon the vesting of restricted units awarded to executive officers to the extent the $1 million limitation is exceeded will not be deductible by the Company. In the future, while the tax impact of compensation arrangements is one factor the Committee will consider, that impact must be evaluated in light of the Company's overall compensation philosophy and objectives. Accordingly, the Committee will seek to qualify compensation for deductibility in instances where it believes that to be in the best interests of the Company but retains discretion to authorize the payment of nondeductible amounts.

Compensation Committee Report -- The Compensation Committee has reviewed the Compensation Discussion and Analysis included above and discussed the same with management of the Company and, based upon that review and discussion, recommends inclusion of the Company's Compensation Discussion and Analysis in this proxy statement.

The Compensation Committee:

Thurmon Andress, Chair
Jonathan M. Clarkson
Robert W. Shower
David F. Work

Pursuant to the SEC Rules, the foregoing Compensation Committee Report is not deemed "soliciting material", is not "filed" with the SEC 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.

SUMMARY COMPENSATION TABLE

The Summary Compensation Table set forth below contains information regarding the combined salary, bonus and other compensation of each of the executive officers with respect to 2006.

Name and Principal Position	Year	Salary	Restricted Stock Awards (1)	Option Awards (2)	Non-Equity Incentive Plan Compensation (3)	All Other Compensation (4)	Total
John W. Elias .... Chairman of the Board, President and Chief Executive Officer	2006	$ 350,000	$ 156,795	$ 68,937	-0-	$ 4,040	$ 579,772
John O. Tugwell .... Executive Vice President and Chief Operating Officer	2006	$ 235,000	$ 100,342	---	$ 56,000	$ 15,000	$ 406,342
Michael G. Long .... Executive Vice President and Chief Financial Officer	2006	$ 227,000	$ 100,342	---	$ 49,900	$ 14,260	$ 391,502

(1) These amounts reflect the dollar amount recognized for financial statement reporting purposes for the fiscal year ended December 31, 2006 in accordance with FAS 123R of awards made pursuant to the Incentive Plan, and thus may include amounts in respect of stock awards granted in and prior to 2006. Pursuant to SEC rules, the amounts shown exclude the impact of estimated forfeitures. A discussion of the assumptions used in calculating these amounts may be found in Note 17 to our 2006 audited financial statements included in our annual report on Form 10-K for the year ended December 31, 2006. These amounts reflect the Company's accounting expense for these awards and do not correspond to the actual value that may be recognized by the executive officers.

(2) The amount reflects the dollar amount recognized for financial statement reporting purposes for the fiscal year ended December 31, 2006 in accordance with FAS 123R of option awards made to Mr. Elias in 2004. Pursuant to SEC rules, the amounts shown exclude the impact of estimated forfeitures. These amounts reflect the Company's accounting expense for these awards and do not correspond to the actual value that may be recognized by executives. A discussion of the assumptions used in calculating these amounts may be found in Note 17 to our 2006 audited financial statements included in our annual report on Form 10-K for the year ended December 31, 2006. These amounts reflect the Company's accounting expense for these awards and do not correspond to the actual value that may be recognized by the executive officers. All option awards to Messrs. Tugwell and Long were fully vested prior to the Company's adoption of FAS 123R; therefore, there was no accounting expense in 2006 for any unexercised options held by them.

(3) These amounts reflect the annual performance-based cash bonus awards for the performance year in which they were earned and are paid on or about April 1 of the following year. For example, the bonuses in the table for 2006 performance were paid on or about April 1, 2007. These awards are discussed in more detail on page 17 under the heading "—2006 Executive Compensation Components-*Performance-Based Cash Bonus.*"

(4) In the case of Mr. Elias, amounts shown represent payments by the Company for life insurance on his account. In the case of Messrs. Tugwell and Long, amounts shown represent the Company's contributions under its 401(k) Plan. None of the executive officers received perquisites with an incremental cost to the Company in excess of $10,000 in 2006.

The 2006 Grants of Plan-Based Awards Table sets forth information regarding the estimated possible payouts of non-equity incentive plan awards to the executive officers based on Company performance and Restricted Stock Awards for 2006.

2006 GRANTS OF PLAN-BASED AWARDS

			Estimated Possible Payouts Under Non-Equity Incentive Plan Awards (1)				
Name	Grant Date	Committee Action Date	Threshold	Target	Maximum	All Other Stock Awards; Number of Shares of Stock or Units(2)	Grant Date Fair Value of Stock Awards(3)
John W. Elias.................	-	-	$0	$227,500	$455,000	-	-
	4/1/06	3/8/06	-	-	-	12,000	$306,840
John O. Tugwell	-	-	$0	$141,000	$282,000	-	-
	4/1/06	3/8/06	-	-	-	5,400	$ 122,161
	10/1/06	8/25/06	-	-	-	30,000	$ 404,427
Michael G. Long............	-	-	$0	$124,850	$249,700	-	-
	4/1/06	3/8/06	-	-	-	5,400	$ 122,161
	10/1/06	8/25/06	-	-	-	30,000	$ 404,427

(1) The amounts shown represent the potential threshold, target and maximum payment levels for 2006 performance under the Company's performance-based cash bonus program (a non-equity incentive plan). These amounts are based upon target and maximum percentages of each executive's base salary and based upon Company and individual performance, as described in "*Performance-Based Cash Bonus*" of the "Compensation Discussion and Analysis" section above. The actual amounts of non-equity incentive plan awards for 2006 performance (paid on or about April 1, 2007) are shown in the Summary Compensation Table under "Non-Equity Incentive Plan Compensation" column for each executive officer. Actual non-equity incentive plan payouts for 2005 performance (paid on or about April 1, 2006) were $190,000 for Mr. Elias, $105,000 for Mr. Tugwell and $95,000 for Mr. Long.

(2) The amounts shown represent shares of common stock of the Company that were granted to each executive officer in 2006. These awards were made under the Company's Incentive Plan. The stock subject to the April 1, 2006 awards vests and will be issued in equal one-third increments on the first, second and third anniversary of the date of grant. The stock subject to the October 1, 2006 award vests and will be issued 20% at the second anniversary date of grant (October 1, 2008) and 40% each on the third and fourth anniversary dates of the grant (October 1, 2009 and 2010).

(3) These amounts reflect the grant date fair market value of the stock awards recognized for financial statement reporting purposes in accordance with FAS 123R.

The following Outstanding Equity Awards at Fiscal Year End 2006 Table provides information with respect to the value of outstanding unexercised stock options and unvested stock awards held by the executive officers as of December 31, 2006.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END 2006

	Option Awards(1)			Stock Awards	
Name	Number of Securities Underlying Unexercised Options Exercisable (1)	Option Exercise Price	Option Expiration Date	Number of Shares or Units of Stock Held That Have Not Vested	Market Value of Non-Vested Shares or Units of Stock Held That Have Not Vested (2)
John W. Elias....................	--	--	--	20,092	$366,478
	200,000	$4.22	01/08/2009	--	--
	50,000	$3.16	01/03/2010	--	--
	50,000	$8.88	01/02/2011	--	--
	50,000	$5.18	01/02/2012	--	--
	24,000	$5.59	04/01/2012	--	--
	50,000	$3.88	01/23/2013	--	--
	50,000	$13.99	04/01/2014	--	--
John O. Tugwell	--	--	--	39,714	$724,383
	8,700	$7.06	05/21/2009	--	--
	1,300	$7.06	05/21/2009	--	--
	12,000	$5.59	04/01/2012	--	--
Michael G. Long..............	--	--	--	39,714	$724,383

(1) All stock options granted by the Company to the executive officers are fully vested and the Company has not issued any stock options to executive officers since 2003 except to Mr. Elias on April 1, 2004. All options granted have a 10-year term. Michael Long has previously exercised all of his available options.

(2) The value shown is based on a closing stock price of $18.24 per share as of December 31, 2006.

Shown below in the 2006 Option Exercises and Stock Vested Table is information regarding the value realized by the executive officers by virtue of the exercise of options or vesting of restricted stock.

2006 OPTION EXERCISES AND STOCK VESTED

	Option Awards		Stock Awards	
Name of Executive Officer	Number of Shares Acquired on Exercise	Value Realized on Exercise(1)	Number of Shares Acquired on Vesting	Value Realized on Vesting(2)
John W. Elias	--	--	5,231	$133,757
John O. Tugwell	15,000	$269,100	5,153	$131,762
Michael G. Long	30,000	$496,500	5,153	$131,762

(1) For value of exercised stock options, the exercise price for the exercised shares was subtracted from the market price at the time of exercise to determine the value realized by exercise of the options.

(2) For restricted stock vesting, a per share price of $25.57 per share was determined by taking the average of the high and low prices of the stock on April 3, 2006, the first business day occurring after the vesting date.

Pension Benefits

The Company does not have any defined benefit pension plan that provides for payments, pensions or other benefits at, following or in connection with retirement.

Non-Qualified Deferred Compensation

The Company does not have any plan that provides for the deferral of compensation on a basis that is not tax-qualified.

POTENTIAL PAYMENTS UPON CHANGE IN CONTROL OR TERMINATION

The Company has entered into three types of agreements with the executive officers, or certain of them as detailed below, that provide for payments upon a termination of employment: employment agreements, change of control severance agreements and restricted stock award agreements under the Incentive Plan.

Employment Agreement with Mr. Elias

Mr. Elias is the only executive officer with whom the Company has entered into an employment agreement. Mr. Elias entered into an employment agreement with the Company effective November 16, 1998. The agreement automatically renews for successive one-year terms and will continue to do so unless either party gives advance notice of non-renewal. Most recently, the agreement renewed through November 16, 2007. If either the Company or Mr. Elias gives notice of termination of employment, no automatic extension shall occur and Mr. Elias' employment will terminate on the third November 16th to occur following the notice of termination of employment; that is his employment will continue for a period of up to three years following the notice.

Right of Company to Terminate Employment. Notwithstanding the provisions regarding the term of agreement described above, the Company has the right to terminate Mr. Elias' employment at any time for any of the following reasons:

- Mr. Elias' death;
- Mr. Elias' becoming incapacitated by accident, sickness or other circumstances that render him mentally or physically incapable of performing the duties and services required of him under the agreement on a full-time basis with reasonable accommodations for a period of at least 120 consecutive days or for a period of 180 business days during any 12-month period (referred to in this description of the employment agreement as "disability");
- For cause (as described below);
- For Mr. Elias' material breach of any material provisions of the agreement that, if correctable, remains uncorrected for 30 days following written notice to Mr. Elias by the Company of such breach; or
- For any reason at the sole discretion of the Board of Directors.

"For cause" means Mr. Elias' gross negligence, gross neglect or willful misconduct in the performance of the duties required of him or his final conviction of a felony or of a misdemeanor involving moral turpitude, excluding misdemeanor convictions relating to the operation of a motor vehicle.

Right of Mr. Elias to Terminate Employment. Notwithstanding the provisions regarding the term of agreement described above, Mr. Elias has the right to terminate his employment under the agreement at any time for any reason in his sole discretion or for any of the following reasons (the reasons below being referred to in this description of the employment agreement as "good reason"):

- Company's material breach of any material provision of the agreement;
- Company's assignment to Mr. Elias of duties and responsibilities that are materially inconsistent with the positions of Chief Executive Officer or Chairman of the Board;
- Company's failure to reappoint Mr. Elias to the positions of Chief Executive Officer and Chairman of the Board; or
- Change in Mr. Elias' principal place of employment by more than 50 miles.

In the case of the first three bullets above, Mr. Elias is required to give notice to the Company of the breach, assignment or failure and such condition must remain uncorrected for 30 days before giving rise to the termination right.

Entitlement to Termination Benefits. Mr. Elias is entitled to the termination benefits described below under the employment agreement if his employment is terminated for any of the following reasons:

- His death or disability;
- Termination of employment by the Company prior to expiration of term of agreement for any reason other than:
  - For cause; or
  - Material breach of agreement by Mr. Elias; or
- Termination by Mr. Elias for good reason.

Termination Benefits. The termination benefits under the employment agreement are as follows:

- continued payment of his base salary then in effect for the unexpired portion of the term of the agreement (a period of up to three years);
- 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);

- a lump sum cash payment equal to his prorated incentive target bonus in the year of termination;
- life insurance coverage ($1,000,000) and annual tax gross-up of premium payments shall continue to be provided for the unexpired portion of the term of the agreement (a period of up to three years);
- 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
- participation in the Company's group health plan (for the same cost the Company charges to active employees) for a period of up to 18 months after the date of termination.

Covenants. The employment agreement of Mr. Elias provides for a covenant limiting competition with the Company during employment with the Company and, except in the event that his termination was by the Board in its sole discretion, for as long as the Company is providing him with termination benefits. The agreement provides that Mr. Elias will not make any unauthorized disclosure of any confidential business information or trade secrets of the Company or its affiliates at any time during or after his employment with the Company and also contains a non-disparagement clause.

Change in Control Agreements

All current employees of the Company, including Messrs. Elias, Tugwell and Long, are parties to severance agreements that provide for certain benefits in the event an involuntary termination of employment occurs within two years of a change of control of the Company. The agreements renew automatically for two-year terms unless the Board elects to terminate the agreement during the 60 days prior to such automatic renewal. Most recently, the agreements for Messrs. Elias, Tugwell and Long were renewed through January 1, 2008. In the event a change of control occurs, the agreements are not subject to termination or amendment for a period of two years after the change of control, and if within the two year period following the change of control , an executive becomes entitled to severance benefits under the agreement, the agreement cannot be terminated.

Change of Control. Change of control is defined as any of the following occurrences:

- The Company is 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);
- The Company 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 will cease to constitute a majority of the Board;
- Any person or entity, including a "group" as contemplated by Section 13(d)(3) of the Securities Exchange Act of 1934, as amended, 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 cease to constitute a majority of the Board; or
- 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.

Involuntary Termination. An involuntary termination means any termination of employment with the Company other than:

- Resignation by the executive (other than a resignation at the request of the Company or a resignation in connection with a change in duties described below);

- Termination by the Company for cause (which is the same as described for purposes of Mr. Elias' employment agreement above);
- Termination due to disability, as defined for purposes of the Company's long-term disability plan;
- Termination due to death; and
- In the case of Mr. Elias, his retirement, which is defined as his voluntary resignation (other than a resignation within 60 days after the date he receives notice of a change in duties or a resignation at the request of the Company).

A resignation of an executive is an involuntary termination if it occurs within 60 days after the date the executive receives notice of a change of duties or a change in duties actually occurs, whichever occurs first. A change in duties means the occurrence, within two years after a change of control, any one of the following:

- A significant reduction in the duties of the executive;
- A reduction in the executive's annual salary or target opportunity under any bonus or incentive compensation plan;
- Receipt of employee benefits by executive that are materially inconsistent with the benefits provided by the Company to executives with comparable duties;
- A change in location of executive's principal place of employment by the Company by more than 50 miles; and
- In the case of Mr. Elias, the Company's failure to reappoint him to the positions of Chief Executive Officer and chairman of the Board.

Severance Benefits. Pursuant to such agreements, if the executive officers' employment by the Company is subject to an involuntary termination occurring within two 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 the sum of his annual salary and targeted annual bonus in the case of Mr. Elias and 2.0 times the sum of their annual salary and targeted annual bonus in the case of each of Messrs. Long and Tugwell;
- Full vesting of any outstanding incentive awards (such as restricted stock grants) that had not previously vested or otherwise become exercisable;
- Continued coverage in Company welfare and benefit plans for up to 36 months as long as the executive continues to pay the premiums or actual cost on the same basis as active employees;
- 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 excise taxes imposed by Section 4999 of the Internal Revenue Code.

In the case of Mr. Elias, if a qualified termination of employment occurs within two years of a change in control, he is entitled to the benefits under his change in control severance agreement, but not under his employment agreement.

Restricted Stock Awards

When a restricted stock award is made by the Company, including those made to the executive officers, under the Incentive Plan, a restricted stock award agreement is entered into between the Company and the individual. The award agreements provide for accelerated vesting of restricted stock at termination of employment if termination is:

- By the Company without cause, as described below;
- By the executive for good reason, as described below;
- Due to death; or
- Due to disability (in the case of Mr. Elias, as defined in his employment agreement and in the case of Messrs. Tugwell and Long as defined in good faith by the Company and/or by the Company's long-term disability plan).

Under the award agreements, "cause" is defined as (1) having the same meaning as defined in any written employment agreement covering the subject employee or, in the absence of an employment agreement, (2) any of the following:

- conviction in a court of competent jurisdiction of any felony or a crime involving moral turpitude;
- the employee's knowing failure or refusal to follow reasonable instructions, policies, standards and regulations of either the Board or the Company;
- continued failure or refusal to faithfully and diligently perform his or her duties of employment;
- continuously conducting himself or herself in an unprofessional, unethical, immoral or fraudulent manner; or
- exhibiting conduct that discredits the Company or is detrimental to the reputation, character and standing of the Company.

Under the award agreements, "good reason" is defined as (1) having the same meaning as defined in any written employment agreement covering the subject employee or, if such agreement exists but that term is not defined, but the agreement contains a provision permitting the executive to voluntarily terminate employment upon the occurrence of certain events on terms substantially equal to a termination by the Company without cause, good reason shall mean any of those events, or, in the absence of an employment agreement provision, (2) any of the following:

- reduction in annual rate of salary;
- failure by the Company to continue an employee benefit plan or the Company taking action to adversely affect the employee's participation in the benefit plan (unless such action adversely affects the senior management of the Company generally);
- assignment to the employee of materially more oppressive or onerous duties;
- relocation of the office more than 20 miles from the current location; or
- failure of the Company to obtain the assumption in writing of the Company's obligations under the award agreement prior to a reorganization, merger, consolidation, disposition of all or substantially all assets or similar transaction in which the Company is not the survivor.

Termination of Employment by the Company for Cause or by the Employee Other than for Good Reason. If an executive officer terminates employment voluntarily, and not for good reason, any restricted stock awarded to the executive officer that has not previously vested is forfeited.

Termination and Change of Control Benefit Tables

Under the individual agreements with the executive officers described above that address their termination of employment, each executive officer would be entitled to receive the following estimated benefits. These disclosed amounts are estimates only and do not necessarily reflect the actual amounts that would be paid to the executive officers, which would only be known at the time that they become eligible for payment and would depend upon the circumstances of the executive officer's separation from the Company. The tables reflect amounts payable under the agreements assuming a termination of employment occurred on December 31, 2006.

John W. Elias. The following table shows the potential payments upon termination for John W. Elias, the Company's Chairman, President and Chief Executive Officer, as if such termination had occurred on December 31, 2006.

	By Mr. Elias			By the Company			
	Resignation or Retirement	For Good Reason Without Change in Control	Due to Change in Duties Following Change in Control(1)	Without Cause	Without Cause Following Change in Control	For Cause	Disability or Death
Salary Continuation (2)		$1,005,890	-	$1,005,890	-	-	$1,005,890
Incentive Bonus (3)	-	$ 227,500	-	$ 227,500	-	-	$ 227,500
Cash Severance (4)	-	-	$1,726,725	-	$1,726,725	-	-
Equity (5)	-	$ 366,478	$ 366,478	$ 366,478	$ 366,478	-	$ 366,478
Health & Welfare(6)	-	$ 31,909	$ 44,964	$ 31,909	$ 44,964	-	$ 31,909
Outplacement Svc.	-	-	$ 6,000	-	$ 6,000	-	-
Tax Gross Up	-	-	-	-	-	-	-
Total	-	$1,631,777	$2,144,167	$1,631,777	$2,144,167	-	$1,631,777

(1) Resignation is required to be given within 60 days after a change in duties.

(2) Under Mr. Elias' employment agreement, if notice of termination was delivered on 12/31/2006, he would receive continuation of his base salary until November 16, 2009.

(3) This value is based upon Mr. Elias' target bonus of 65% of base salary for 2006 and is included separately from the cash severance amount only to illustrate payments required to be made under his employment agreement. His employment agreement provides that such payment be prorated for months of service during the year; assuming termination of employment on December 31, 2006, 100% of the target bonus amount ($227,500) would be payable. Payment would be a lump sum within three months of termination.

(4) Cash severance payments are payable upon a qualified termination of employment following a change of control and are defined as 2.99 times the sum of Mr. Elias' current salary plus his targeted bonus opportunity.

(5) Represents the potential value of accelerated vesting of shares of restricted stock that have been awarded to Mr. Elias but were unvested as of December 31, 2006 (20,092 shares) based upon the closing share price on December 31, 2006 ($18.24). All stock option awards held by Mr. Elias are fully vested, so no amount is included for early vesting.

(6) Includes an approximate cost to the Company to continue payment of supplemental life insurance premiums in the amount of $9,427 if termination benefits are paid under Mr. Elias' employment agreement, which amount may not be due upon Mr. Elias' death.

John O. Tugwell. The following table shows the potential payments upon termination of employment for John O. Tugwell, the Company's Executive Vice President and Chief Operating Officer, as if such termination had occurred on December 31, 2006.

	By Mr. Tugwell			By the Company			
	Resignation or Retirement	For Good Reason Without Change in Control	Due to Change in Duties Following Change in Control(1)	Without Cause	Without Cause Following Change in Control	For Cause	Disability or Death
Cash Severance (2)	-	-	$ 752,000	-	$ 752,000	-	-
Equity (3)	-	$ 724,383	$ 724,383	$ 724,383	$ 724,383	-	$ 724,383
Health & Welfare	-	-	$ 58,896	-	$ 58,896	-	-
Outplacement Svc.	-	-	$ 6,000	-	$ 6,000	-	-
Tax Gross Up	-	-	-	-	-	-	-
Total	-	$ 724,383	$1,541,279	$ 724,383	$1,541,279	-	$ 724,383

(1) Resignation is required to be given within 60 days after a change in duties.

(2) Cash severance payments are payable upon a qualified termination of employment following a change of control and are defined as 2.00 times the sum of Mr. Tugwell's current salary plus his targeted bonus opportunity.

(3) Represents the potential value of accelerated vesting of shares of restricted stock that have been awarded to Mr. Tugwell but were unvested (39,714 shares) as of December 31, 2006 based upon the closing share price on December 31, 2006 ($18.24). All stock option awards held by Mr. Tugwell are fully vested, so no amount is included for early vesting.

Michael G. Long. The following table shows the potential payments upon termination of employment for Michael G. Long, the Company's Executive Vice President, Chief Financial Officer and Treasurer, as if such termination had occurred on December 31, 2006.

	By Mr. Long			By the Company			
	Resignation or Retirement	For Good Reason Without Change in Control	Due to Change in Duties Following Change in Control(1)	Without Cause	Without Cause Following Change in Control	For Cause	Disability or Death
Cash Severance (2)	-	-	$ 703,700	-	$ 703,700	-	-
Equity (3)	-	$ 724,383	$ 724,383	$ 724,383	$ 724,383	-	$ 724,383
Health & Welfare	-	-	$ 58,680	-	$ 58,680	-	-
Outplacement Svc.	-	-	$ 6,000	-	$ 6,000	-	-
Tax Gross Up	-	-	-	-	-	-	-
Total	-	$ 724,383	$1,492,763	$ 724,383	$1,492,763	-	$ 724,383

(1) Resignation is required to be given within 60 days after a change in duties.

(2) Cash severance payments are payable upon a qualified termination of employment following a change of control and are defined as 2.00 times the sum of Mr. Long's current salary plus his targeted bonus opportunity.

(3) Represents the potential value of accelerated vesting of shares of restricted stock that have been awarded to Mr. Long but were unvested (39,714 shares) as of December 31, 2006 based upon the closing share price on December 31, 2006 ($18.24). Mr. Long exercised all of his stock options prior to December 31, 2006, so no amount is included for early vesting.

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, 2006.

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	647,424	$6.52	501,446
Equity compensation plan not approved by security holders	461,000	$5.53	--
Total	1,108,424	$5.82	501,446

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.

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(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 457,724 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 189,700 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, which provides for awards of restricted stock and of options for the purchase of Common Stock, was approved by the Board of Directors of the Company and 475,000 shares of Common Stock were initially reserved for issuance thereunder, of which no shares remain available for additional awards at December 31, 2006. As of December 31, 2006, 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, 2006. The Elias Plan provided 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 non-qualified stock options 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 also provides for an award of 14,000 shares of restricted stock to Mr. Elias effective March 1, 2001, which vested 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 became 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.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth information as of March 1, 2007 (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 March 1, 2007, 28,383,455 shares of Common Stock were issued and outstanding. As of March 1, 2007, 2,875,000 shares of Convertible Preferred Stock were issued and outstanding. Each share of Convertible Preferred Stock is convertible at any time at the option of the holder thereof into approximately 3.0193 shares of Common Stock, subject to adjustments. However, upon conversion, we have the right to deliver, in lieu of shares of Common Stock, cash or a combination of cash and shares of Common Stock. No Directors or executive officers of the Company held any shares of Convertible Preferred Stock as of March 1, 2007.

Name (1)	Number of Shares of Common Stock Beneficially Owned	Percent of Common Stock Beneficially Owned
John W. Elias (2)	719,832	2.49%
John O. Tugwell (3)	62,787	*
Michael G. Long (4)	73,680	*
Thurmon Andress (5)	23,946	*
Vincent S. Andrews (6)	48,651	*
Jonathan M. Clarkson	8,511	*
Michael A. Creel	12,511	*
Stanley S. Raphael (7)	246,629	*
John Sfondrini (8)	20,648	*
Robert W. Shower	17,643	*
David F. Work (9)	18,521	*
Royce & Associates, LLC (10)	3,358,114	11.51%
All Directors and executive officers as a group (11 persons) (11)	1,253,359	4.33%

* 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) 474,000 shares of Common Stock that could be acquired pursuant to stock options exercisable within 60 days of March 1, 2007, (ii) 215,000 shares purchased by Mr. Elias's IRA account pursuant to the Company's 1999 private placement on the same terms as were applicable to unrelated parties; and (iii) 9,231 shares that Mr. Elias will receive within 60 days of March 1, 2007 pursuant to restricted stock awards made in 2004, 2005 and 2006.

(3) Shares shown include (i) 22,000 shares of Common Stock that could be acquired pursuant to stock options exercisable within 60 days of March 1, 2007; (ii) 4,553 shares that Mr. Tugwell will receive within 60 days of March 1, 2007, pursuant to restricted stock awards made in 2004, 2005 and 2006; and (iii) 1,719 shares held in the Company's 401(k) plan.

(4) Shares shown include (i) 4,553 shares that Mr. Long will receive within 60 days of March 1, 2007 pursuant to restricted stock awards made in 2004, 2005 and 2006; and (ii) 1,130 shares held in the Company's 401(k) plan.

(5) Shares shown include (i) 8,000 shares of Common Stock that could be acquired pursuant to stock options exercisable within 60 days of March 1, 2007 and (ii) 4,000 shares of Common Stock held by Andress Oil & Gas LP, a limited partnership of which Mr. Andress serves as managing partner. Mr. Andress may be deemed the beneficial owner of the shares of Common Stock beneficially owned by Andress Oil & Gas LP. Mr. Andress disclaims such beneficial ownership except to the extent of his pecuniary interest in such limited partnership.

(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) 21,300 shares that could be acquired pursuant to stock options exercisable within 60 days of March 1, 2007. 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. 8,783 of the shares that are held by Mr. Andrews and 15,000 of the shares that are held by Mr. Andrews' wife are pledged as collateral for a loan.

(7) Shares shown include (i) 98,455 shares of Common Stock held by the Trade Consultants, Inc. Pension Plan, of which Mr. Raphael is the trustee, (ii) 52,986 shares held by the Stanley Raphael Trust, a trust controlled by Mr. Raphael, (iii) 42,718 shares held by a trust for the benefit of Mr. Raphael's wife, (iv) 19,000 shares held by Trade Consultants Inc. of which Mr. Raphael is sole owner and director, (v) 5,000 shares held by the SSR Trust, a trust controlled by Mr. Raphael, and (vi) 21,300 shares that could be acquired pursuant to stock options exercisable within 60 days of March 1, 2007. 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. 50,986 of the shares that are held by the Stanley Raphael Trust are pledged as collateral for a loan.

(8) 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, and (ii) 4,998 shares held by Mr. Sfondrini's children. 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. 15,200 of the shares that are held by Mr. Sfondrini are pledged as collateral for a loan.

(9) Shares also include 8,000 shares of Common Stock that could be acquired pursuant to stock options exercisable within 60 days of March 1, 2007.

(10) The business address of this beneficial holder is 1414 Avenue of the Americas, New York, New York 10019. The information regarding Royce & Associates, LLC is based on filings made with the SEC reflecting beneficial ownership of the convertible Preferred Stock as of January 31, 2007 and beneficial ownership of the Common Stock as of February 28, 2007. Shares shown include 800,114 shares of Common Stock that may be obtained through the conversion of Convertible Preferred Stock. On January 31, 2007, Royce & Associates, LLC acquired 265,000 shares of Convertible Preferred Stock. Based on the conversion rate of 3.0193 discussed above, Royce & Associates, LLC would have the right to acquire 800,114 shares of Common Stock, assuming we do not exercise our right to deliver, in lieu of shares of Common Stock, cash or a combination of cash and shares of Common Stock.

(11) Shares shown include (i) 554,600 shares of Common Stock that may be acquired pursuant to stock options exercisable within 60 days of March 1, 2007, and (ii) 18,337 shares of restricted Common Stock that executive officers will receive within 60 days of March 1, 2007.

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 2006 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.

TRANSACTIONS WITH RELATED PERSONS

Purchases of Oil and Gas Properties from Affiliates

The Company is a defendant, along with other working interest owners in certain wells, in a lawsuit filed in Louisiana generally relating to whether or not the actions of the operator (a predecessor of Anadarko Petroleum) of those wells, were those of a prudent operator and/or negligent, thereby causing damage to the plaintiffs. Of the 18.75% after-payout working interest that was originally reserved in the relevant leases, the Company owned an approximate 2.8% working interest at the time of the alleged acts or omissions. In September 2005, the Company filed a third-party demand to join the other working interest owners who own the remainder of the 18.75% working interest as third-party defendants in this case. These third-parties consist, for the most part, of partnerships that are directly or indirectly controlled by John Sfondrini, and hold an aggregate 14.797% working interest (the "Sfondrini Partnerships"). The Sfondrini Partnerships consist of (1) Edge Group Partnership, a general partnership composed of limited partnerships of which Mr. Sfondrini and a company controlled by Mr. Sfondrini are general partners; (2) Edge Option I Limited Partnership, Edge Option II Limited Partnership and Edge Option III Limited Partnership, limited partnerships of which Mr. Sfondrini and a company controlled by Mr. Sfondrini are general partners; and (3) BV Partners Limited Partnership, a limited partnership of which a company controlled by Mr. Sfondrini is general partner. Mr. Sfondrini serves as a manager of each of the Sfondrini Partnerships, for which he receives management fees. Other than an approximately 20% ownership interest in Edge Group Partnership, his ownership interests in the Sfondrini Partnerships are not material in size or economic value. On December 19, 2006, the Company, along with the other defendants, reached a settlement agreement with plaintiffs holding 72% of the total claims in the suit (the "Broussard Plaintiffs") in full settlement of their claims. The Company's share of this settlement totaled $206,000 and the Sfondrini Partnerships' share totaled $1,109,759. The settlement with the Broussard plaintiffs was finalized on February 1, 2007, and the defendants, including the Company and the third-party defendants including the Sfondrini Partnerships, were released from all claims by the Broussard plaintiffs.

In order to facilitate the settlement, the Company purchased certain oil and gas properties from certain of the Sfondrini Partnerships (as the Sfondrini Partnerships, collectively had sufficient assets, but not sufficient cash, available to finance the settlement), with the proceeds of such sale and purchase generally being directed to payment of the Broussard settlement, in full satisfaction of the Sfondrini Partnerships' share of such settlement. The valuations of the interests of the Sfondrini Partnerships purchased by the Company and the interests contributed to Edge Group Partnership by BV Partners and Edge Option I, II and III Limited Partnerships, as discussed below, were arrived at using a PV10 model and assuming $7.50/MMBtu gas and $60/BBl oil, which the Company believed represented current pricing levels for oil and gas properties at the time, and were agreed to by the Company and Mr. Sfondrini, on behalf of the Sfondrini Partnerships. Any excess value that accrues to these interests due to any future increasing product price or other reasons would benefit the Company.

The oil and gas properties that the Company purchased from the Sfondrini Partnerships and their respective purchase prices are as follows:

(1) 100% of each of Edge Group Partnership's, Edge Option I Limited Partnership's, Edge Option II Limited Partnership's and Edge Option III Limited Partnership's interest in the Ilse Miller No. 2 Well and leases, Wharton County, Texas, for a total combined value of $51,243.

(2) 100% of each of Edge Group Partnership's, Edge Option I Limited Partnership's, Edge Option II Limited Partnership's and Edge Option III Limited Partnership's interest in the Wm Baas 2-16 No. 1 Well and leases, Monroe County, Alabama, for a total combined value of $14,407.

(3) 55.953% of Edge Group Partnership's interest in certain wells and leases in the Company's Austin and Nita prospects, for a total value of $1,044,109.

In the purchase and sale transaction between the Company and the Sfondrini Partnerships, BV Partners Limited Partnership, whose share of the Broussard settlement amount was $186,000 (as determined by the Company and Mr. Sfondrini on behalf of the BV Partners Limited Partnership), did not sell any assets to the Company and did not have sufficient funds to satisfy its share of the settlement amount. In addition, the Edge Option I, II and III Limited Partnerships did not have sufficient assets to satisfy their respective 0.34%, 0.34% and 2.25% shares of the settlement amount, which the Company and Mr. Sfondrini determined to be $25,750, $25,750 and $169,102, respectively. The shortfall amounts of Edge Option I, II and III Limited Partnerships were, net of assets that they sold to the Company, determined by the Company and Mr. Sfondrini to be $24,333, $24,333 and $163,276, respectively. As a result, Edge Group Partnership sold additional properties (over the amount necessary to fund its portion of the settlement) to the Company at fair market value in an amount sufficient to allow it to have proceeds from such sale to fund BV Partners Limited Partnership's share of the settlement and the remaining shortfall amounts owed by Edge Option I, II and III Limited Partnerships. These properties are included in the amounts set forth above as being purchased by the Company from the Sfondrini Partnerships. In return, BV Partners and Edge Option I, II and III Limited Partnerships contributed all of their interest in the Bayou Vermilion Prospect leases and the Trahan No. 3 well located thereon to Edge Group Partnership. The fair market value of these interests contributed to Edge Group by BV Partners Limited Partnership and Edge Option I, II and III Limited Partnerships were determined by the Company and Mr. Sfondrini on behalf of such partnerships to be $27,793, $3,847, $3,847 and $25,263, respectively.

Affiliates' Ownership in Prospects

The transactions described below were carried out with parties that may be deemed to be affiliates, and it is possible that the Company would have obtained different terms from a truly unaffiliated third party.

The following parties own certain working interests in the Company's Nita and Austin Prospects and certain other wells and prospects operated by the Company: (1) Edge Group Partnership, a general partnership composed of three limited partnerships of which Mr. Sfondrini and a company wholly owned by Mr. Sfondrini are general partners; (2) Edge Holding Company, L.P., a limited partnership of which Mr. Sfondrini and a corporation wholly owned by him are the general partners; and (3) 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. These working interests, as of December 31, 2006, aggregate 13.96% in the Austin Prospect, 5.04% 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 by the Company to these parties represent their respective pro-rata ownership shares in the particular properties involved. In September 2006, Essex I and Essex II sold all of their interests in wells operated by the Company except for one well in which Essex I has a 1% gross working interest. Prior to the sale, Essex I and Essex II also owned royalty and overriding royalty interests in various wells operated by the Company, with the combined royalty and overriding royalty interests of Essex I and Essex II not exceeding 6.2% in any one such well or prospect. The gross amounts distributed or accrued to these persons and entities by the Company in 2006 on account of their proportionate ownership interests (including net revenue, royalty and overriding royalty interests) and the amounts these same parties 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 2006 including Overriding Royalty*	Lease Operating Expenses paid to the Company by Owners in 2006
Edge Group Partnership	$428,321	$308,516
Edge Holding Company, L.P.	$ 76,169	$ 54,422
Essex I	$ 18,641	-0-
Essex II	$112,912	$ 64,248
Total	$636,043	$427,186

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

Related Party Transaction Policies and Procedures

As set forth in writing in the Audit Committee Charter, related party transactions are subject to review and approval by the Audit Committee to the extent required by Nasdaq rules. For this purpose, related party transactions are transactions required to be disclosed pursuant to Item 404(a) of Regulation S-K. In order to identify related party transactions, among other measures, the Company requires its directors and officers to complete questionnaires identifying transactions with the company in which the officer or director or their family members may have an interest. In addition, our Code of Ethics for employees, directors and officers requires employees to disclose possible conflicts of interest to the Company.

PROPOSAL II

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 2007. 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.

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, 2006 and 2005, respectively, 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. Audit-related fees include BDO Seidman, LLP's due diligence review of mergers and acquisitions and audits of acquisitions during the years ended December 31, 2006 and 2005, respectively. Also set forth in the table below are amounts billed for tax services performed by BDO Seidman, LLP for the Company during 2006, namely (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 2005 and 2006 and are reflected in the columns below.

	Fiscal 2006	Fiscal 2005
Audit Fees	$598,566	$ 506,539
Audit-related Fees	$468,582	$ 74,918
Tax Fees	-	$ 3,968
Other	-	-

The Audit Committee pre-approved all of the services described above that were provided during the fiscal year ended December 31, 2006 in accordance with the Audit Committee's policy (discussed below) and the pre-approval requirements of the Sarbanes-Oxley Act. Accordingly, there were no services for which the de minimis exception, as defined in Section 202 of the Sarbanes-Oxley Act, was applicable.

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 III

Other Business

Management does not intend to bring any business before the meeting other than the election of Directors and the 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 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 2008 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 2007 Annual Meeting, stockholders who wish to nominate directors or to bring business before the 2008 Annual Meeting of stockholders must notify the Company no later than January 24, 2008. 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 2008 Annual Meeting of stockholders must be received by the Company no later than December 21, 2007. However, if the date of the 2008 Annual Meeting of stockholders changes by more than 30 days from the first anniversary of the date of the 2007 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 if it differs from the date set forth above. Stockholder proposals must also be otherwise eligible for inclusion.

By Authorization of the Board of Directors

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

April 19, 2007

EDGE PETROLEUM CORPORATION
ANNUAL MEETING OF STOCKHOLDERS

10:00 a.m., May 23, 2007

Hyatt Regency Hotel
1200 Louisiana Street
Houston, Texas 77002

ADVANCE REGISTRATION

Attendance at the Annual Meeting is limited to holders of shares of Common Stock of Edge Petroleum Corporation (the "Company") (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 April 5, 2007, or you must provide a copy of a brokerage statement or other evidence of beneficial ownership showing your ownership of Edge shares on April 5, 2007. Attendees may register at the door on the day of the meeting; however, advance registration for the 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.

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MR A SAMPLE
DESIGNATION (IF ANY)
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Electronic Voting Instructions

You can vote by Internet or telephone!
Available 24 hours a day, 7 days a week!

Instead of mailing your proxy, you may choose one of the two voting methods outlined below to vote your proxy.

VALIDATION DETAILS ARE LOCATED BELOW IN THE TITLE BAR.

Proxies submitted by the Internet or telephone must be received by 5:30 p.m. Central Daylight Time on May 22, 2007.

Vote by Internet

- Log on to the Internet and go to **www.investorvote.com**
- Follow the steps outlined on the secured website.

Vote by telephone

- Call toll free 1-800-652-VOTE (8683) within the United States, Canada & Puerto Rico any time on a touch tone telephone. There is NO CHARGE to you for the call.
- Follow the instructions provided by the recorded message.

Using a <u>black ink</u> pen, mark your votes with an X as shown in this example. Please do not write outside the designated areas. X

Annual Meeting Proxy Card

123456 C0123456789 12345

▼ IF YOU HAVE NOT VOTED VIA THE INTERNET <u>OR</u> TELEPHONE, FOLD ALONG THE PERFORATION, DETACH AND RETURN THE BOTTOM PORTION IN THE ENCLOSED ENVELOPE. ▼

A Proposals — The Board of Directors recommends a vote <u>FOR</u> all the nominees listed and <u>FOR</u> Proposal 2.

1. Election of Directors:

	For	Withhold
01 - Robert W. Shower	☐	☐
02 - David F. Work	☐	☐

	For	Against	Abstain
2. PROPOSAL TO APPROVE THE APPOINTMENT OF BDO SEIDMAN, LLP as the independent registered public accounting firm for the Company for 2007.	☐	☐	☐

3. With discretionary authority as to such other matters as may properly come before the meeting.

Advance Registration: Check here if you or your designated representative or proxy and/or a member of your immediate family plan to attend the meeting. Write in space below the name of any such intended attendee. ☐

Change of Address — Please print new address below.

B Authorized Signatures — This section must be completed for your vote to be counted. — Date and Sign Below

If signing as Attorney, Administrator, Executor, Guardian, Trustee or Corporate Officer, please add your title as such.
Please sign, date and return promptly.

Date (mm/dd/yyyy) — Please print date below.	Signature 1 — Please keep signature within the box.	Signature 2 — Please keep signature within the box.
/ /		

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<STOCK#> 00PX7B

▼ IF YOU HAVE NOT VOTED VIA THE INTERNET OR TELEPHONE, FOLD ALONG THE PERFORATION, DETACH AND RETURN THE BOTTOM PORTION IN THE ENCLOSED ENVELOPE. ▼

Proxy — EDGE PETROLEUM CORPORATION

Proxy Solicited on Behalf of the Board of Directors
Annual Meeting of Stockholders to be held Wednesday, May 23, 2007

The undersigned hereby appoints Michael G. Long and Robert C. Thomas, jointly and severally, proxies, with full power of substitution and with discretionary authority, to represent and to vote, in accordance with the instructions set forth below, all shares of Common Stock which the undersigned is entitled to vote at the 2007 annual meeting of stockholders of Edge Petroleum Corporation (the "Company"), to be held on Wednesday, May 23, 2007, at the Hyatt Regency Hotel, 1200 Louisiana, Houston, Texas 77002, at 10:00 a.m. (the "Annual Meeting") or at any adjournment thereof, hereby revoking any proxy heretofore given. **THIS PROXY, WHEN PROPERLY EXECUTED, WILL BE VOTED IN THE MANNER DIRECTED HEREIN. IN THE ABSENCE OF SPECIFIC DIRECTIONS TO THE CONTRARY, THIS PROXY WILL BE VOTED FOR THE ELECTION OF EACH OF THE DIRECTORS NAMED ON THE REVERSE SIDE AND FOR THE APPROVAL OF BDO SEIDMAN, LLP AS THE COMPANY'S INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FOR 2007, AND IN THE DISCRETION OF THE PROXIES, UPON SUCH OTHER BUSINESS AS MAY PROPERLY COME BEFORE THE MEETING.**

The undersigned hereby acknowledges receipt of the notice of, and Proxy Statement for, the aforesaid Annual Meeting.

YOUR VOTE IS IMPORTANT. If you will not be voting by telephone or the Internet, you are urged to complete, sign, date and promptly return the accompanying proxy in the enclosed envelope, which is postage prepaid if mailed in the United States. If you will be voting by telephone or the Internet, there is no need for you to mail back the accompanying proxy.

(Continued and to be dated and signed on reverse side)

Corporate Information

Board of Directors

Thurmon Andress
President, Andress Oil & Gas Company

Vincent Andrews
President, Vincent Andrews Management Corporation

Jonathan M. Clarkson
President, Houston Region, Texas Capital Bank

Michael A. Creel
Executive Vice President and Chief Financial Officer, Enterprise Products GP, LLC

John W. Elias
Chairman, President and CEO

Stanley Raphael
Director, American Polymers, Inc.; President, Trade Consultants Inc.

John Sfondrini
Private Investor

Robert W. Shower
Executive Vice President and Chief Financial Officer, Seagull Energy Corporation, Retired

David F. Work
North American Vice President, BP, Retired

[1] Member of audit committee
[2] Member of compensation committee
[3] Member of corporate governance/nominating committee
[4] Retiring from Board in May 2007

Officers and Management

John W. Elias
Chairman, President and CEO

Michael G. Long
Executive Vice President and Chief Financial Officer

John O. Tugwell
Executive Vice President and Chief Operating Officer

Howard Creasey
Senior Vice President Exploration

C.W. MacLeod
Senior Vice President Business Development and Planning

Robert C. Thomas
Senior Vice President, General Counsel and Corporate Secretary

Kurt P. Primeaux
Vice President Production

R. Keith Turner
Vice President Land

Corporate Headquarters

Edge Petroleum Corporation
1301 Travis, Suite 2000
Houston, Texas 77002
(713) 654-8960
www.edgepet.com

Transfer Agent

For information regarding change of address, lost certificates or similar inquiries, please contact our transfer agent and registrar by calling 1-303-298-5370 or by writing:
Computershare, Investor Services
P.O. Box 1596
Denver, Colorado 80201-1596

Outside Legal Counsel

Baker Botts L.L.P.
Houston, Texas

Independent Registered Public Accounting Firm

BDO Seidman, LLP
Houston, Texas

Market Information

The Company's common stock and convertible preferred stock trade on the Nasdaq Global Select Market under the symbols EPEX and EPEXP.

Annual Meeting

The Annual Meeting of Shareholders is scheduled to be held at 10:00 a.m. on May 23, 2007 at:
Hyatt Hotel
1200 Louisiana Street
Houston, Texas 77002

Form 10-K

A copy of the Company's Annual Report on Form 10-K to the Securities and Exchange Commission is included as an integral part of this Annual Report to Shareholders. Additional copies may be obtained, without charge, by writing to:
Edge Petroleum Corporation
c/o Investor Relations
1301 Travis, Suite 2000
Houston, Texas 77002

***Cautionary Note to Investors** – The United States Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use certain terms in this document, such as resource potential, that the SEC's guidelines strictly prohibit us from including in filings with the SEC. These terms include reserves with substantially less certainty than proved reserves. U.S. Investors are urged to consider closely the disclosure in our attached Form 10-K.*

Projections, estimates and other statements herein that are not historical facts are forward-looking statements. Actual results may differ materially from those expected or projected as a result of various factors, including those described in "Risk Factors" in the attached Form 10-K and the Company's other SEC filings.

Definitions

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

Cash Margin *Revenue less lease operating expenses, production and ad valorem taxes, net interest and dividend expenses and other G&A expenses, which excludes compensation expenses related to options, restricted stock and bad debt expense*

Mcf *One thousand cubic feet*

Mcfe *One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids*

MMcf *One million cubic feet*

MMcfe *One million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids*

R/P *Reserve to production ratio calculated by dividing annual production by total year-end proved reserves*

EDGE PETROLEUM CORPORATION
1301 TRAVIS STREET, SUITE 2000
HOUSTON, TEXAS 77002
(713) 654-8960

END