2007

REX ENERGY CORPORATION
2007 ANNUAL REPORT AND FORM 10-K

WWW.REXENERGY.COM

NASDAQ: REXX

REX ENERGY CORPORATION 2007 ANNUAL REPORT

CEO'S LETTER TO STOCKHOLDERS

REX ENERGY CORPORATION
(NASDAQ: REXX)

I am pleased to report that 2007 was an extraordinary year for our company. During 2007, we completed our initial public offering and significantly reduced our outstanding indebtedness, which has positioned us to better accomplish our growth objectives.

During the year, some of our significant accomplishments included:

Financial Strength. We improved our balance sheet, reducing debt by more than $75 million. Additionally, we established a new senior credit facility, which has provided us with an available line of credit of up to $75 million.

Production Growth. We increased annual production by 30% from 772 thousand barrels of oil equivalent ("MBOE") in 2006 to just over 1.0 million barrels of oil equivalent ("MMBOE") in 2007.

Financial Performance. Our revenue increased by 46% in 2007 over the previous year, and our EBITDAX grew by 39% over the previous year to $25.3 million.

Proven Reserves Growth. During 2007, we achieved a reserve replacement rate of 139%. Our proven reserves grew by 10% to 15.9 million barrels of oil equivalent over the previous year, and our present value of future cash flows before taxes, or PV-10, grew by 96% to $392.1 million.

Debt Reduced 75%

Revenue Up 46%

Production Up 31%

EBITDAX Up 39%

Proven Reserves Up 10%

Reserve Replacement of 139%

As we look forward into 2008, we are excited about our growth prospects, including our enhanced oil recovery project in the Illinois Basin; our two shale exploration projects in the Marcellus Shale of Pennsylvania and the New Albany Shale of Indiana and Illinois; our developmental drilling prospects in Pennsylvania, Illinois, and Indiana; and our exploration and developmental projects in the Southwestern Region of the United States.

I would like to thank both our individual and institutional stockholders for your continued interest and support of Rex Energy Corporation. We remain determined to create value for you in 2008 and beyond.

Benjamin W. Hulburt
President and CEO
March 31, 2008

REX ENERGY CORPORATION 2007 ANNUAL REPORT

PROFILE

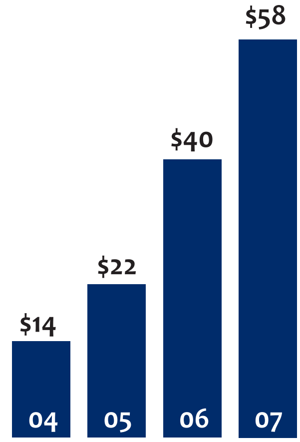
Rex Energy Corporation (NASDAQ: REXX) is an independent oil and gas company engaged in the acquisition, production, exploration and development of oil and gas, with properties concentrated in the Appalachian Basin, Illinois Basin and Southwestern Region of the United States. We pursue a balanced growth strategy of exploiting our sizeable inventory of lower risk developmental drilling locations, pursuing our higher potential exploration drilling prospects and actively seeking to acquire complementary oil and natural gas properties. Our success can be attributed to our seasoned and diversified management team comprised of expert personnel, using the latest technologies and sound business practices.

2007 HIGHLIGHTS

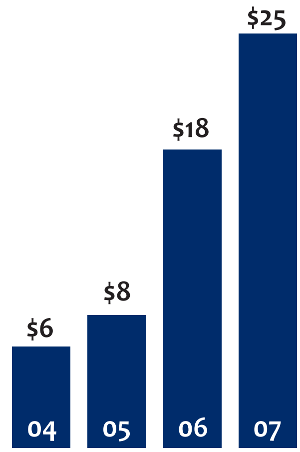
- Proven reserves for year-end 2007 increased 10% to 15.9 MMBOE from 14.5 MMBOE for year-end 2006;
- 2007 total net production volumes reached a record high of 1.0 MMBOE, up 31% from the same period in 2006;
- 2007 operating revenues grew 46% over 2006 to $57.8 million;
- 2007 EBITDAX grew 39% over 2006 to $25.3 million;
- 4th quarter 2007 average net daily production reached a record high of 2,831 barrels of oil equivalent ("BOE") per day;
- 4th quarter 2007 operating revenues reached a record high of $16.1 million; and
- Drilled 85 gross (68.3 net) wells in 2007 with a 99% success rate.

SIGNIFICANT GROWTH OPPORTUNITIES

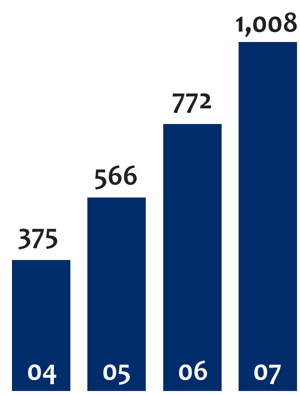
- Alkali-Surfactant-Polymer ("ASP") enhanced oil recovery project in the largest field in the Illinois Basin;
- Marcellus Shale exploration on approximately 36,000 net acres in Pennsylvania as of April 7, 2008;
- New Albany Shale exploration on approximately 92,000 net acres as of April 7, 2008; and
- Developmental drilling in Illinois, Appalachian and Permian Basins on approximately 500 drilling and recompletion locations.



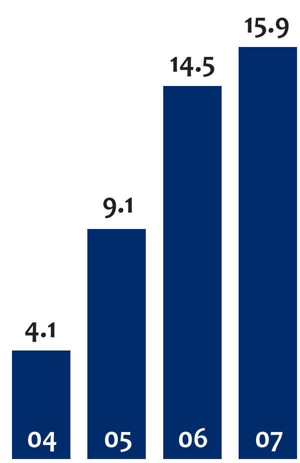
Total Revenue
(in millions)



EBITDAX
(in millions)



Total Production
(in MBOE)



Total Proved Reserves
(in MMBOE)

BUILT-IN FUTURE GROWTH WITH STABLE FOUNDATION

Proven Reserve Base[1]

- 15.9 MMBOE Proven Reserves
- 81% Oil
- 78% Proved Developed
- $392.1 million PV-10

Developmental Drilling

- ~ 200 additional non-proven shallow oil locations in the Illinois Basin
- ~ 100 additional non-proven shallow natural gas locations in the Appalachian Basin
- ~ 25 additional non-proven oil and gas locations in the Permian Basin

Enhanced Oil Recovery (Lawrence Field ASP Project)[2]

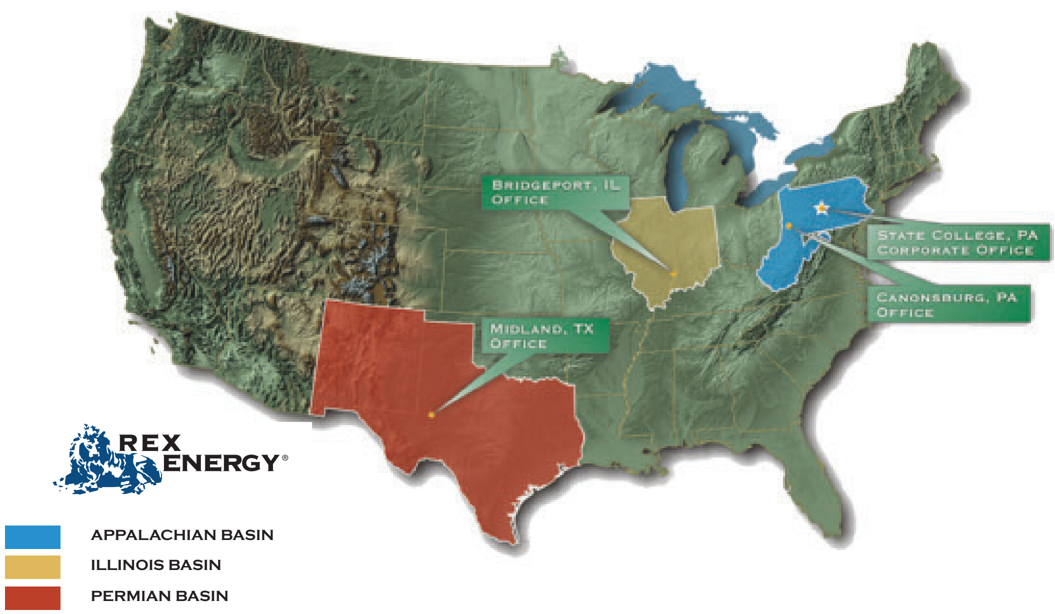
- 84 million Barrels ("MMBbls") in net un-risked potential reserves
- Expected Finding and Development ("F&D") costs of ~$11.00 per Barrel ("Bbl")
- Project PV-10 of $1.5 billion at $80.00 oil with 97% Internal Rate of Return

Marcellus Shale Potential

- As of April 7, 2008, 36,000 net acres in areas of active exploration of Pennsylvania[3]
- Actively leasing additional acreage
- ~900 net potential vertical locations (40 acres spacing) / ~360 net potential horizontal locations (100 acre spacing)
- ~735 Billion cubic feet ("Bcf") in net un-risked potential reserves[2]

Other

- As of April 7, 2008, 306,000 (92,000 net) acres in southern Indiana in areas with active New Albany Shale exploration
- ASP potential in additional fields and formations we own in the Illinois Basin



AREAS OF OPERATION

Our operations are concentrated in three producing basins, the Appalachian, Illinois and the Southwestern Region of the United States. Headquartered in State College, Pennsylvania, we also have offices in Pittsburgh, Pennsylvania; Midland, Texas; and Bridgeport, Illinois.

(1) Prepared by Netherland, Sewell & Associates, Inc. as of December 31, 2007.
(2) Internally prepared, does not represent proven reserves.
(3) As of April 7, 2008.

ILLINOIS BASIN

Since entering the Illinois Basin in 2004, we have pursued an aggressive growth plan that has made us the region's largest oil producer.

- 4th quarter 2007 average net production (BOE per day): 2,136
- Net undeveloped acreage: 85,000
- Year-end 2007 proven reserves (MMBOE): 12.0
- Significant potential from enhanced oil recovery (ASP) project with up to 84 million barrels of net un-risked reserve potential
- New Albany Shale drilling potential on over 306,000 gross (92,000 net) acres as of April 7, 2008
- Active developmental drilling with 99% success in shallow oil zones in 2007

APPALACHIAN BASIN

- 4th quarter 2007 average net production (MMcf per day): 2.5
- Net undeveloped acreage: 18,000
- Proven reserves (MMBOE): 2.1
- Marcellus Shale potential on more than 64,000 gross (36,000 net) acres as of April 7, 2008
- Actively leasing additional acreage for Marcellus Shale potential
- Active developmental drilling with 100% success in shallow gas zones in 2007

SOUTHWESTERN REGION

- 4th quarter 2007 average net production (BOE per day): 281
- Net undeveloped acreage: 1,500
- Proven reserves (MMBOE): 1.8
- Queen Sand, Leonard, Connell, San Andres and Grayburg drilling projects
- Waterflood installation and optimization projects

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

FORM 10-K

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

For the fiscal year ended December 31, 2007

Commission file number: 001-33610

REX ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**20-8814402**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. employer identification number)**

**1975 Waddle Road
State College, Pennsylvania 16803**
**(Address of principal executive offices)
(Zip Code)**

(814) 278-7267
(Registrant's telephone number, including area code)

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

Title of Class	**Name of each exchange where registered**
Common Stock, $.001 par value per share	**The NASDAQ Stock Market LLC**

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 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, a non-accelerated filer or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "small reporting company" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ Smaller reporting company ☐

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

The Registrant completed the initial public offering of its common stock in July 2007. Accordingly, there was no market for the Registrant's common stock as of June 30, 2007, the last day of the Registrant's most recently completed second fiscal quarter.

30,794,702 common shares, $.001 par value, were outstanding on March 28, 2008.

REX ENERGY CORPORATION

FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2007

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements within the meaning of sections 27A of the Securities Act of 1933, as amended, and 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included in this report, including but not limited to, statements regarding our future financial position, business strategy, budgets, projected costs, savings and plans and objectives of management for future operations, are forward-looking statements. Forward-looking statements generally can be identified by the use of forward-looking terminology such as "may," "will," "expect," "intend," "estimate," "anticipate," "believe" or "continue" or the negative thereof or variations thereon or similar terminology.

These forward-looking statements are subject to numerous assumptions, risks and uncertainties. Factors which may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by us in those statements include, among others, the following:

- the quality of our properties with regard to, among other things, the existence of reserves in economic quantities;
- uncertainties about the estimates of reserves;
- our ability to increase our production and oil and natural gas income through exploration and development;
- our ability to successfully apply horizontal drilling techniques and tertiary recovery methods;
- the number of well locations to be drilled, the cost to drill and the time frame within which they will be drilled;
- the timing and extent of changes in commodity prices for crude oil and natural gas;
- domestic demand for oil and natural gas;
- drilling and operating risks;
- the availability of equipment, such as drilling rigs and transportation pipelines;
- changes in our drilling plans and related budgets;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity; and
- other factors discussed under "Risk Factors" in Item 1A of this report.

Because such statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by the forward-looking statements. You are cautioned not to place undue reliance on such statements, which speak only as of the date of this report. Unless otherwise required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

SPECIAL NOTE REGARDING THE REGISTRANT

In this report, we refer to certain companies—Douglas Oil & Gas Limited Partnership, Douglas Westmoreland Limited Partnership, Midland Exploration Limited Partnership, New Albany—Indiana, LLC, PennTex Resources, L.P., PennTex Resources Illinois, Inc., Rex Energy Limited Partnership, Rex Energy II Limited Partnership, Rex Energy III LLC, Rex Energy IV, LLC, Rex Energy II Alpha Limited Partnership, Rex Energy Operating Corp. and Rex Energy Royalties Limited Partnership—collectively as the "Predecessor Companies." In this report, we refer to each of the Predecessor Companies individually as:

Douglas Oil & Gas Limited Partnership	"Douglas Oil & Gas"
Douglas Westmoreland Limited Partnership	"Douglas Westmoreland"
Rex Energy Royalties Limited Partnership	"Rex Royalties"
Midland Exploration Limited Partnership	"Midland"
New Albany-Indiana, LLC	"New Albany"
PennTex Resources Illinois, Inc	"PennTex Illinois"
PennTex Resources, L.P	"PennTex Resources"
Rex Energy Limited Partnership	"Rex I"
Rex Energy II Limited Partnership	"Rex II"
Rex Energy II Alpha Limited Partnership	"Rex II Alpha"
Rex Energy III LLC	"Rex III"
Rex Energy IV, LLC	"Rex IV"
Rex Energy Operating Corp	"Rex Operating"

Simultaneously with the consummation of our initial public offering of common stock, through a series of mergers and reorganization transactions, which we refer to as the "Reorganization Transactions," Rex Energy Corporation acquired all of the outstanding equity interests of the Predecessor Companies. Unless otherwise indicated, all references to "Rex Energy Corporation," "our," "we," "us" and similar terms refer to Rex Energy Corporation and its subsidiaries together with the Predecessor Companies, after giving effect to the Reorganization Transactions.

Beginning on page 135 of this report, we have included a glossary of oil and natural gas terms used throughout this report.

PART I

ITEM 1. BUSINESS

General

We are an independent oil and gas company operating in the Illinois Basin, the Appalachian Basin and the Southwestern Region of the United States. We pursue a balanced growth strategy of exploiting our sizeable inventory of lower risk developmental drilling locations, pursuing our higher potential exploration drilling prospects and actively seeking to acquire complementary oil and natural gas properties. We were incorporated in the state of Delaware on March 8, 2007. We completed our initial public offering and the Reorganization Transactions in July 2007. Our common stock currently trades on the NASDAQ Global Market under the symbol "REXX".

At December 31, 2007, our proved reserves had the following characteristics:

- 15.9 MMBOE;
- 81% crude oil;
- 78% proved developed; and
- A reserve life index of approximately 15 years (based upon fourth quarter 2007 production).

At December 31, 2007, we operated approximately 2,341 wells. For the quarter ended December 31, 2007, we produced an average of 2,831 net BOE per day, composed of approximately 81% oil and approximately 19% natural gas.

We are one of the largest oil producers in the Illinois Basin, with average net daily production of 2,109 barrels of oil per day in 2007. In addition to our developmental shallow oil drilling and exploratory shale drilling projects in the Illinois Basin, we are in the process of implementing an enhanced oil recovery project, or EOR project, in the Lawrence Field in Lawrence County, Illinois, which we refer to as our Lawrence Field ASP Flood Project.

In our Appalachian Basin, we averaged net production of approximately 2.2 MMcf in 2007 of natural gas per day and are continuing to grow our reserves and production in the region through developmental shallow natural gas drilling and exploratory drilling, including our Marcellus Shale drilling projects. While we do not currently have proven reserves in the Marcellus Shale, as of March 20, 2008, we control approximately 60,000 gross (30,000 net) acres in areas of Pennsylvania, which we believe are prospective for the Marcellus Shale exploration.

We averaged net production of approximately 1.8 MMcfe per day in our Southwestern Region in 2007 and currently have several active drilling and redevelopment projects within that region, including drilling projects in the Queen, Leonard, Canyon and San Andres formations. At December 31, 2007, we owned interests in 152 wells located in west Texas and southeast New Mexico and we operated 93 of these wells.

Our total operating revenues for the year ended December 31, 2007 were $57.8 million. Revenues were derived from $63.5 million in oil and natural gas sales and $452,000 in other revenues, partially offset by $6.2 million in realized losses on derivatives.

For the year ended December 31, 2007, we drilled 85 gross (68.3 net) wells. The wells drilled in 2007 include 57 that were productive, 10 gross (10 net) producer wells and 7 gross (7 net) injector wells related to our Lawrence Field ASP Flood Project, one well that was deemed to be a dry hole and 10 gross (3.8 net) exploratory wells that are still being evaluated, eight of which are New Albany Shale wells.

The following table shows selected data concerning our production, proved reserves and undeveloped acreage in our three operating regions for the periods indicated:

Basin/Region	Annual 2007 Average Daily BOE	Total Proved MMBOE (As of December 31, 2007)	Percent of Total Proved MMBOE	PV-10 (As of December 31, 2007) (In Millions)(1)	Total Net Undeveloped Acres (As of December 31, 2007)(2)
Illinois Basin	2,109	12.0	75.4%	$336.5	84,942
Appalachian Basin	359	2.1	13.3%	25.9	18,115
Southwestern Region	294	1.8	11.3%	29.7	1,486
Total	2,762	15.9	100.0%	$392.1	104,543

(1) Represents the present value, discounted at 10% per annum (PV-10), of estimated future net cash flows before income tax of our estimated proved reserves. PV-10 is a non-GAAP financial measure because it excludes the effects of income taxes and asset retirement obligations. PV-10 should not be considered as an alternative to the pro forma standardized measure of discounted future net cash flows as defined under GAAP. At December 31, 2007, our standardized measure was $255.0 million. For an explanation of why we show PV-10 and a reconciliation of PV-10 to the standardized measure of discounted future net cash flows, please read "Selected Financial and Operating Data—Non-GAAP Financial Measures." Please also read "Risk Factors—Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves."

(2) Undeveloped acreage is 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 includes proved reserves.

Our Competitive Strengths

We believe our historical success has been, and future performance will be, directly related to the following combination of strengths that we believe enable us to implement our strategy:

Significant Production Growth Opportunities: We have several projects and properties that we believe are capable of resulting in significant proved reserves and production growth. These include:

- our Lawrence Field ASP Flood Project in Illinois (please see "Item 2. Properties—Illinois Basin—The Lawrence Field ASP Flood Project");
- our large acreage positions in two unconventional shale exploration projects with approximately 60,000 gross (30,000 net) acres in Pennsylvania prospective for the Marcellus Shale (please see "Item 2. Properties—Appalachian Basin—Marcellus Shale"); and approximately 306,000 gross acres (92,000 net) in southern Indiana prospective for the New Albany Shale as of March 20, 2008 (please see "Item 2. Properties—Illinois Basin—New Albany Shale");
- our conventional shallow natural gas drilling opportunities in the Appalachian Basin and our conventional shallow oil drilling opportunities in the Illinois Basin; and
- our oil and gas developmental and exploratory drilling and redevelopment projects in the Southwestern Region.

Market Leader in the Illinois Basin: We believe we are one of the largest oil producers and a market leader in the Illinois Basin, which enables us to realize a current premium over the basin posted prices on our oil production and a competitive cost structure due to economies of scale, and provides us with a unique local knowledge of the basin. We believe these advantages may enhance our ability to continue making strategic acquisitions in the basin.

Experienced Management Team with a Proven Track Record: We feel we have significant technical and managerial experience in our core operating areas. Our technical team of geologists and engineers have an average of over 20 years of experience, primarily in the Illinois, Appalachian and Permian Basins. We believe the experience and capabilities of our management team have enabled us to build a high quality asset base of proved reserves and growth projects, both organically and through selective acquisitions.

Financial Flexibility: As of December 31, 2007, we had approximately $27 million in debt outstanding, representing a 7.6% debt to market capitalization at December 31, 2007 and value of $11.93 per share. In addition, our senior credit facility had a borrowing capacity of $75 million as of December 31, 2007, of which approximately $48 million was available for working capital purposes or to fund new acquisitions. Lastly, we believe our oil and gas financial derivative activities enable us to achieve more predictable cash flows and reduce our exposure to short-term fluctuations in oil and natural gas prices while we continue to develop our properties.

For a more detailed discussion of our derivative activities, see the information see the information set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Incentivized Management Ownership: As of March 31, 2008, our directors and officers beneficially owned approximately 52% of our outstanding common stock. Therefore, we believe the interests of our directors and executive officers are closely aligned with those of our stockholders.

Business Strategy

Our strategy is to increase stockholder value by profitably increasing our reserves, production, cash flow and earnings. The following are key elements of our strategy:

Employ Technological Expertise: Our strategy is to utilize and expand the technological expertise that has enabled us to achieve a drilling completion rate of approximately 94% during the last three years and has helped us improve operations and enhance field recoveries. We intend to apply this expertise to our proved reserve base and our development projects.

Develop Our Existing Properties: Our focus is to develop our asset base in each of our operating basins including:

- our Lawrence Field ASP Flood Project in Illinois;
- our New Albany Shale resource play with over 306,000 gross (92,000 net) acres;
- our Marcellus Shale natural gas play with approximately 60,000 gross (30,000 net) acres; and
- our inventory of approximately 500 proved undeveloped locations and proved developed non-producing wells.

Pursue Strategic Acquisitions and Joint Ventures: We plan to continue to acquire and lease additional oil and natural gas properties in our core areas of operation. We believe that our strong history of acquisitions, leading position in the Illinois Basin and technical expertise position us well to attract joint venture partners and pursue strategic acquisitions.

Focus on Operations: We focus our future acquisition and leasing activities on properties where we have a significant working interest and can operate the property to control and implement the planned exploration and development activity.

Reduce Per Unit Operating Costs Through Economies of Scale and Efficient Operations: As we continue to increase our oil and natural gas production and develop our existing properties, we believe that our per unit production costs can benefit from increased production in lower cost operations and through better use of our existing infrastructure over a larger number of wells.

Maintain Flexibility: Because of the volatility of commodity prices and the risks involved in our industry, we believe in remaining flexible in our capital budgeting process. When appropriate, we may defer capital projects to seize an attractive acquisition opportunity or reallocate capital towards projects where we believe we can generate higher than anticipated returns. We also believe in maintaining a strong balance sheet and using commodity hedging. This allows us to be more opportunistic in lower price environments as well as providing more consistent financial results.

Equity Ownership and Incentive Compensation: We believe our performance is enhanced when our employees think and act like owners. To achieve this, we believe in rewarding and encouraging our employees through equity ownership in our company. As of March 31, 2008, our employees owned approximately 3.5 million shares of our common stock, representing 11.4% of our total outstanding shares of common stock.

Significant Accomplishments in 2007

During 2007, our significant accomplishments included:

- **Successful completion of our initial public offering:** We completed our initial public offering in July 2007.
- **Financial Strength:** We improved our balance sheet, reducing debt by more than $75 million since closing our initial public offering. Additionally, we established a new cost-effective senior credit facility, which has provided us with an available line of credit of up to $75 million.
- **Production Growth:** We increased annual production by 30% from 772 MBOE in 2006 to just over 1.0 MMBOE in 2007.
- **Financial Performance:** Our revenue increased by 46% in 2007 over the previous year, and our EBITDAX, as defined on page 41 of this report, grew by 39% over the previous year to $25.3 million.
- **Proven Reserves Growth:** During 2007, we achieved a reserve replacement rate of 139%. Our proven reserves grew by 10% over the previous year to 15.9 MMBOE, and the present value of future cash flows before taxes, or PV-10, grew by 96% to $392 million.
- **Successful Drilling Program:** In 2007, we drilled 57 gross developmental wells. Our overall success rate was 99%.
- **Continued Expansion of Drilling Inventory:** To continue to grow, the size of our prospect inventory must remain large. Our drilling inventory currently includes over 3,000 net potential drilling locations. During 2007, we expanded our acreage position in the Marcellus Shale play by approximately 40%. As of March 20, 2008, we controlled approximately 60,000 gross (30,000 net) acres in this emerging play in Pennsylvania. Over the remainder of 2008, we plan to continue to expand our position in the Marcellus Shale play as well as commence pilot operations in our Lawrence Field ASP Flood Project in the Illinois Basin. We are continuing to retain additional experienced technical professionals to assist us in these significant projects.

Plans for 2008

In November 2007, we established an initial capital budget of approximately $78 million in 2008, which equated to an increase of 95% over the 2007 capital expenditures. The 2008 initial capital budget plan reflected our plans to accelerate our Lawrence Field ASP Flood Project, to commence the testing of our acreage in Pennsylvania for the Marcellus Shale, and to continue to drill our developmental drilling projects in the Appalachian Basin, Illinois Basin and Southwestern Region.

On March 17, 2008, our board of directors approved an increase in our 2008 capital budget to $139 million. The increase was the result of increased anticipated capital expenditures in our Marcellus Shale leasing activities from $4.5 million to $57.1 million, as well as an increase in anticipated drilling activities from $4.2 million to $8.9 million.

The following table summarizes our actual 2007 and our revised estimated 2008 capital expenditures ($ in millions). The estimated capital expenditures are dependent on a number of factors, including industry conditions and our drilling success, and are subject to change. We do not attempt to budget for future acquisitions of proved oil and gas properties.

	For the Years Ended December 31,	
	2007 (actual)	**2008 (estimated)**
Capital Expenditures		
Illinois Basin Conventional Oil Operations	$14.8	$ 16.5
Lawrence Field ASP Flood Project	4.5	29.9
Shale Projects	3.2	16.1
Appalachian Basin Operations	5.2	7.1
Southwestern Region Operations	4.0	9.9
Acquisitions of proved oil and gas properties	2.3	—
Acquisitions and leasing of undeveloped properties	5.4	58.6
Other Capital Expenditures	1.0	0.6
Total Capital Expenditures	$40.4	$138.7

Production, Revenues and Price History

The following table sets forth information regarding oil and gas production and revenues for the last three years ($ in thousands):

	Production and Revenue by Region For the Years Ended December 31,		
	2007	2006	2005
Appalachian Region:			
Revenue	$ 5,725	$ 5,460	$ 6,470
Oil Production (Bbls)	—	—	—
Natural Gas Production (Mcf)	786,095	707,755	701,265
Total Production (BOE)(1)	131,016	117,959	116,878
Oil Average Sales Price	$ —	$ —	$ —
Natural Gas Average Sales Price	$ 7.28	$ 7.71	$ 9.23
Illinois Region:			
Revenue	$ 52,408	$ 33,328	$ 18,486
Oil Production (Bbls)	769,911	546,231	343,225
Natural Gas Production (Mcf)	—	—	—
Total Production (BOE)(1)	769,911	546,231	343,225
Oil Average Sales Price	$ 68.07	$ 61.02	$ 53.86
Natural Gas Average Sales Price	$ —	$ —	$ —
Southwestern Region:			
Revenue	$ 5,392	$ 4,808	$ 4,562
Oil Production (Bbls)	44,946	41,239	35,729
Natural Gas Production (Mcf)	373,904	401,739	423,478
Total Production (BOE)(1)	107,263	108,196	106,309
Oil Average Sales Price	$ 69.73	$ 59.70	$ 52.29
Natural Gas Average Sales Price	$ 6.04	$ 5.84	$ 6.36
Total Company:			
Revenue	$ 63,525	$ 43,596	$ 29,518
Oil Production (Bbls)	814,857	587,470	378,954
Natural Gas Production (Mcf)	1,159,999	1,109,494	1,124,743
Total Production (BOE)(1)	1,008,190	772,386	566,411
Oil Average Sales Price	$ 68.16	$ 60.92	$ 53.71
Natural Gas Average Sales Price	$ 6.88	$ 7.04	$ 8.15

(1) Natural gas is converted at the rate of six Mcf to one BOE and oil is converted at a rate of one Bbl to one BOE

Competition

The oil and gas industry is intensely competitive, particularly with respect to the acquisition of prospective oil and natural gas properties and oil and natural gas reserves. Our ability to effectively compete is dependent on our geological, geophysical and engineering expertise and our financial resources. We must compete against a substantial number of major and independent oil and natural gas companies that have larger technical staffs and greater financial and operational resources than we do. Many of these companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also have refining operations, market refined products and generate electricity. We also compete with other oil and natural gas companies to secure drilling rigs and other equipment necessary for drilling and completion of wells. Consequently, drilling equipment may be in short supply from time to time. Currently, access to additional drilling equipment in certain of our regions is difficult. Additionally, it is difficult to attract and retain employees, particularly those with expertise in high demand areas.

Employees

As of December 31, 2007, we had 115 full-time employees, 83 of whom were field personnel. No employees are covered by a labor union or other collective bargaining arrangement. We believe that our relations with our employees are good. We regularly utilize independent consultants and contractors to perform various professional services, particularly in the areas of drilling, completion, field services and on-site production operation services.

Marketing and Customers

We market nearly all of our oil and gas production from the properties we operate for both our interest and that of the other working interest owners and royalty owners.

In the Illinois Basin, we store the oil produced at well site tanks and sell our oil to Countrymark Cooperative, LLP, a local refinery, currently at a premium to the basin posted prices. This premium is provided to us due to our significant size in the basin relative to other local producers. The oil is purchased at our tank facilities from the refiner and trucked to refinery facilities. The revenue we derived from our sales to Countrymark Cooperative, LLP for the year ended December 31, 2007 constituted approximately 82% of our oil and natural gas sales revenue for such period. As such, we are currently significantly dependent on the creditworthiness of Countrymark Cooperative, LLP. Please read "Item 1A Risk Factors—We depend on a relatively small number of customers for a substantial portion of our revenue. The inability of one or more of our purchasers to meet their obligations or the loss of our market with Countrymark Cooperative, LLP, in particular, may adversely affect our financial results."

We are currently in the process of constructing our own offload facility at a nearby crude oil pipeline operated by Marathon Oil Corp. that will enable us to diversify our purchasers in the future should the need arise. In the Appalachian Basin, our natural gas producing properties are located near existing pipeline systems and processing infrastructure. The majority of our production is transported over our own gathering lines to local distribution companies. In the Appalachian Basin, due to its proximity to large east coast cities, we generally receive a premium over market prices for our gas production of approximately $0.25-$0.50 per Mcf. In the Southwestern Region, we market our oil and gas production to various oil purchasers and pipeline systems at facilities located near our existing gathering systems or well site tanks.

Prices for oil and natural gas fluctuate fairly widely based on, among other things, supply and demand. Supply and demand are influenced by a number of factors, including weather, foreign policy and industry practices. For example, demand for natural gas has increased in recent years due to a trend in the power plant industry to use natural gas as a fuel source instead of oil and coal because natural gas is a cleaner burning fuel. Demand for oil has increased due to increased industrialization in many parts of the world. Nonetheless, because of historical fluctuations in prices, there can be no assurance at what price we will be able to sell our oil and natural gas. Prices may be low when our wells are most productive, thereby reducing overall returns.

We enter into derivative transactions with unaffiliated third parties to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in oil and gas prices. For a more detailed discussion, see the information set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 7A. Quantitative and Qualitative Disclosures about Market Risk."

Governmental Regulations

Our oil and natural gas exploration, production and related operations are subject to extensive rules and regulations promulgated by federal, state, tribal and local authorities and agencies. For example, some states in which we operate require permits for drilling operations, drilling bonds or reports concerning operations, and impose other requirements relating to the exploration for and production of oil and natural gas. In addition, states in which we operate may have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production

from wells, and the regulation of spacing, plugging and abandonment of wells. Failure to comply with any such rules or regulations can result in substantial penalties. The increasing regulatory burden on the oil and natural gas industry will most likely increase our cost of doing business and may affect our profitability. Although we believe we are currently in substantial compliance with all applicable laws and regulations, because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. We may be required to make significant expenditures to comply with governmental laws and regulations, which could have a material adverse effect on our business, financial condition and results of operations.

Our operations are subject to various types of regulation at the federal, state and local levels that:

- require permits for the drilling of wells;
- require permits to drill wells on federal lands, which generally require a minimum of 60-120 days to obtain;
- require permits to drill wells on state land and fee lands, which generally require a minimum of 30-60 days to obtain;
- mandate that we maintain bonding requirements in order to drill or operate wells; and
- regulate 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, temporary storage tank operations, air emissions from flaring, compression and access roads, sour gas management, and the disposal of fluids used in connection with operations.

Our operations are also subject to various conservation laws and regulations. These regulations govern the size of drilling and spacing units or proration units, the density of wells that may be drilled in oil and natural gas properties and the unitization or pooling of natural gas and oil properties. In this regard, some states allow the forced pooling or integration of lands and leases to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is primarily or exclusively 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, some state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose specified requirements regarding the ratability of production. On some occasions, tribal and local authorities have imposed moratoria or other restrictions on exploration and production activities that must be addressed before those activities can proceed. The effect of all 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. Where our operations are located on federal lands, the timing and scope of development may be limited by the National Environmental Policy Act. The regulatory burden on the oil and natural gas industry increases our costs of doing business and, consequently, affects our profitability. Because these laws and regulations are frequently expanded, amended and reinterpreted, we are unable to predict the future cost or impact of complying with applicable environmental and conservation requirements.

The Federal Energy Regulatory Commission, or FERC, regulates interstate natural gas transportation rates and service conditions. Its regulations affect the marketing of natural gas produced by us, as well as the revenues that may be received by us for sales of such production. Since the mid-1980s, FERC has issued a series of orders, culminating in Order Nos. 636, 636-A and 636-B, collectively, Order 636, that have significantly altered the marketing and transportation of natural gas. Order 636 mandated a fundamental restructuring of interstate pipeline sales and transportation service, including the unbundling by interstate pipelines of the sale, transportation, storage and other services such pipelines previously performed. One of FERC’s purposes in issuing Order 636 was to increase competition within the natural gas industry. Generally, Order 636 has eliminated or substantially reduced the interstate pipelines’ traditional role as wholesalers of natural gas in favor of providing only storage and transportation service, and has substantially increased competition and volatility in natural gas markets.

The price we receive from the sale of oil and natural gas liquids will be affected by the cost of transporting products to markets. Effective January 1, 1995, FERC implemented regulations establishing an indexing system for transportation rates for oil pipelines, which, generally, index such rates to inflation, subject to certain conditions and limitations. We are unable to predict the effect, if any, of these regulations on our intended operations. The regulations may, however, increase transportation costs or reduce well head prices for oil and natural gas liquids.

Environmental Matters

Our operations and properties are subject to extensive and changing federal, state and local laws and regulations relating to environmental protection and the discharge of materials into the environment. These laws and regulations:

- require the acquisition of permits or other authorizations before construction, drilling and certain other of our activities;
- limit or prohibit construction, drilling and other activities on specified lands within wilderness and other protected areas; and
- impose substantial liabilities for pollution that may result from our operations.

The permits required for our operations may be subject to revocation, modification and renewal by issuing authorities. Governmental authorities have the power to enforce environmental laws and regulations, and violations may result in fines, injunctions, or even criminal penalties. We believe that we are in substantial compliance with current applicable environmental laws and regulations, and, except for those matters described in Item 3 “Legal Proceedings,” have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, the trend in environmental legislation and regulation generally is toward stricter standards, and we expect that this trend will continue. Changes in existing environmental laws and regulations or in interpretations thereof could have a significant impact on us, as well as the oil and natural gas industry as a whole.

The following is a summary of the existing laws and regulations that could have a material impact on our business operations.

The Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency, or EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration and production of crude oil or natural gas are currently regulated under RCRA’s non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial condition.

The Comprehensive Environmental, Response, Compensation, and Liability Act, as amended, or CERCLA, and comparable state statutes impose strict, joint and several liability on owners and operators of sites and on persons who disposed of or arranged for the disposal of “hazardous substances” found at such sites. The classes of persons considered responsible for a release 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. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production, and produced water disposal operations for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been disposed of or released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes or property contamination, or to perform remedial activities to prevent future contamination.

The Federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Our oil and natural gas exploration and production operations generate produced water as a waste material, which is subject to the disposal requirements of the Clean Water Act, Safe Drinking Water Act, or SDWA, or an equivalent state regulatory program. This produced water is disposed of by re-injection into the subsurface through disposal wells, discharge to the surface, or in evaporation ponds. Whichever disposal method is used, produced water must be disposed of in compliance with permits issued by regulatory agencies, and in compliance with applicable environmental regulations. This water can sometimes be disposed of by discharging it under discharge permits issued pursuant to the Clean Water Act or an equivalent state program. Another common method of produced water disposal is subsurface injection in disposal wells. Such disposal wells are permitted under the SDWA, or an equivalent state regulatory program. To date, we believe that all necessary surface discharge or disposal well permits have been obtained and that the produced water has been discharged into the produced water disposal wells in substantial compliance with such obtained permits and applicable laws and regulations.

The Federal Clean Air Act, and comparable state laws, regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Federal Clean Air Act and associated state laws and regulations.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal, or cleanup requirements could materially adversely affect our operations and financial position, as well as those of the oil and gas industry in general. For instance, recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to such studies, the U.S. Congress is actively considering climate change-related legislation to restrict greenhouse gas emissions. One bill recently approved by the U.S. Senate Environment and Public Works Committee, known as the Lieberman—Warner Climate Security Act or S. 2191, would require a 70% reduction in emissions of greenhouse gases from sources within the United States between 2012 and 2050. A vote on this bill by the full Senate is expected to occur before mid-year 2008. For example, at least nine states in the Northeast (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York and Vermont) and five states in the West (Arizona, California, New Mexico, Oregon and Washington) have passed laws, adopted regulations or undertaken regulatory initiatives to reduce the emission of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse

gas cap and trade programs. Also, as a result of the U.S. Supreme Court's decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may be required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The EPA has indicated that it will issue a rulemaking notice to address greenhouse gas emissions from vehicles and automobile fuels, although the date for the issuance of this notice has not been finalized. The Court's holding in *Massachusetts* that greenhouse gases fall under the federal Clean Air Act's definition of "air pollutant" may also result in future regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. Other nations have already agreed to regulate emissions of greenhouse gases pursuant to the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol," an international treaty pursuant to which participating countries (not including the United States) have agreed to reduce their emissions of greenhouse gases to below 1990 levels by 2012. Passage of climate control legislation or other regulatory initiatives by Congress or various states of the United States, or the adoption of regulations by the EPA and analogous state agencies that restrict emissions of greenhouse gases in areas in which we conduct business could have an adverse affect on our operations and demand for our products.

The National Environmental Policy Act, or NEPA, requires a thorough review of the environmental impacts of "major federal actions" and a determination of whether proposed actions on federal land would result in "significant impact." In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. NEPA review can increase the time for obtaining approval of, and impose additional regulatory burdens on, our exploration and production activities on federal lands, thereby increasing our costs of doing business and decreasing our profitability.

Available Information

We maintain an internet website under the name "www.rexenergy.com." We make available, free of charge, on our website, our annual report 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 providing such reports to the SEC. Our Corporate Governance Policy, the charters of the Audit Committee, the Compensation Committee and the Nominating and Governance Committee, and the Code of Ethics for directors, officers, employees and financial officers are also available on our website and in print to any stockholder who provides a written request to the Corporate Secretary at 1975 Waddle Rd., State College, PA 16803.

We file annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934, as amended. The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including Rex Energy Corporation, that file electronically with the SEC. The public can obtain any document we file with the SEC at www.sec.gov. Information contained on or connected to our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

ITEM 1A. RISK FACTORS

In evaluating our company, the factors described below should be considered carefully. The occurrence of one or more of these events could significantly and adversely affect our business, prospects, financial condition, results of operations and cash flows.

Risks Related to Our Company

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

The prices we receive for our oil and natural gas production heavily influence our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in global supply and demand for oil and natural gas;
- the actions of certain foreign states;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions, including embargoes, in or affecting other oil producing activities;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- production or pricing decisions made by the Organization of Petroleum Exporting Countries (OPEC);
- weather conditions;
- availability of limited refining facilities in the Illinois Basin reducing competition and resulting in lower regional oil prices than other U.S. oil producing regions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically. Our reserve base is heavily weighted towards oil producing properties many of which are utilizing or proposed for secondary recovery methods characterized by higher operating costs than many other types of fields such as those in their primary recovery stage or natural gas fields. The higher operating costs associated with many of our oil fields will make our profitability more sensitive to oil price declines. Lower prices will also negatively impact the value and quantity of our proved and unproved projects. A substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Enhanced Oil Recovery, or EOR, techniques that we may use, such as our Alkali-Surfactant-Polymer flooding in the Lawrence Field, involve more risk than traditional waterflooding.

EOR techniques such as alkali-surfactant-polymer, or ASP, chemical injection involve significant capital investment and an extended period of time, generally a year or longer, from the initial phase of a pilot program until increased production occurs. Our Lawrence Field ASP Flood Project is in its very early stages and the

results of our pilot program could be unsuccessful. In addition, the results of any successful pilot program may not be indicative of actual results achieved in a broader EOR project in the same field or area. Generally, surfactant polymer, including ASP, injection is regarded as involving more risk than traditional waterflood operations. The potential reserves associated with our ASP project in the Lawrence Field are not considered proved. Our ability to achieve commercial production and recognize proved reserves from our EOR projects is greatly contingent upon many inherent uncertainties associated with EOR technology, including ASP technology, geological uncertainties, chemical and equipment availability, rig availability and many other factors.

We have limited experience in drilling wells to the Marcellus Shale and less information regarding reserves and decline rates in the Marcellus Shale than in other areas of our Appalachian operations. Wells drilled to the Marcellus Shale will be deeper, more expensive and more susceptible to mechanical problems in drilling and completing than wells in the other areas.

We have limited experience in drilling wells to the Marcellus Shale. As of December 31, 2007, we have not drilled any wells to the Marcellus Shale. Other operators in the Appalachian Basin also have limited experience in drilling wells to the Marcellus Shale. Thus, we have much less information with respect to the ultimate recoverable reserves and the production decline rate in the Marcellus Shale than we have in our other areas of operation. In addition, the wells to be drilled in the Marcellus Shale will be drilled deeper than in our other primary areas, which make the Marcellus Shale wells more expensive to drill and complete. The wells will also be more susceptible to mechanical problems associated with the drilling and completion of the wells, such as casing collapse and lost equipment in the wellbore. In addition, the fracturing of the Marcellus Shale will be more extensive and complicated than fracturing the geological formations in our other areas of operation.

Absent a sufficient level of vertical fracturing in the shale acreage we control, our New Albany Shale projects may not be successful.

New Albany Shale reservoirs are complex, often containing unusual features that are not well understood by drillers and producers. These formations are believed to contain natural fractures. Results of past drilling in these formations have been mixed and are generally believed to be related to whether or not a particular well bore intersects vertical fractures. Certain areas in the New Albany Shale will be more heavily fractured than others. If our acreage is not subject to the level of natural fracturing that we expect, our plan for horizontal drilling would not yield our expected results and our business, results of operations or financial condition could be materially adversely affected.

A significant part of the value of our production and reserves is concentrated in the Illinois Basin. Because of this concentration, any production problems or changes in assumptions affecting our proved reserve estimates related to these areas could have a material adverse impact our business.

For the year ended December 31, 2007, 76% of our net daily production came from the Illinois Basin area, and, as of December 31, 2007, approximately 75% of our proved reserves were located in the fields that comprise this area. In addition, for the year ended December 31, 2007, approximately 54% of our net daily production came from the Lawrence Field, and, as of December 31, 2007, approximately 53% of our proved reserves were located on this property. Moreover, we plan to allocate approximately 21% of our 2008 capital expenditures to our Lawrence Field ASP Flood Project. If mechanical problems, weather conditions or other events were to curtail a substantial portion of this production, our cash flow could be adversely affected. If ultimate production associated with these properties is less than our estimated reserves, or changes in pricing, cost or recovery assumptions in the area results in a downward revision of any estimated reserves in these properties, our business, financial condition or results of operations could be adversely affected.

We depend on a relatively small number of purchasers for a substantial portion of our revenue. The inability of one or more of our purchasers to meet their obligations or the loss of our market with Countrymark Cooperative, LLP, in particular, may adversely affect our financial results.

We derive a significant amount of our revenue from a relatively small number of purchasers. All of the oil we produce in the Illinois Basin is sold to one refinery, Countrymark Cooperative, LLP. The revenue we received from sales of our oil to Countrymark Cooperative, LLP for the year ended December 31, 2007, constituted approximately 82% of our total oil and natural gas sales revenue for such period. Our inability to continue to provide services to key customers, if not offset by additional sales to our other customers, could adversely affect our financial condition and results of operations. These companies may not provide the same level of our revenue in the future for a variety of reasons, including their lack of funding, a strategic shift on their part in moving to different geographic areas in which we do not operate or our failure to meet their performance criteria. The loss of all or a significant part of this revenue would adversely affect our financial condition and results of operations.

PennTex Illinois and Rex Operating are defendants in a putative class action lawsuit concerning complaints of hydrogen sulfide emissions from the Lawrence Field, which could expose us to monetary damages or settlement costs.

PennTex Illinois and Rex Operating are defendants in a putative class action lawsuit asserting that the operation of oil wells that are controlled, owned or operated by PennTex Illinois and Rex Operating has resulted in contamination of the areas surrounding Bridgeport and Petrolia, Illinois, with hydrogen sulfide, or H_2S. The complaint, as amended, asserts several causes of action, including violation of the Illinois Environmental Protection Act, violation of the federal Resource Conservation And Recovery Act, negligence, private nuisance, trespass, and willful and wanton misconduct. The complaint seeks, among other things, injunctive relief under the Illinois Environmental Protection Act and Illinois common law, compensatory and other damages, punitive damages, and attorneys' fees and costs. In addition, the complaint seeks the creation of a court-supervised, defendant-financed fund to pay for medical monitoring for the plaintiffs and others in the class area. The plaintiffs have filed a motion for class certification requesting that the court certify the case as a class action.

We intend to vigorously oppose the plaintiffs' motion for class certification and the claims that have been asserted by the plaintiffs' against PennTex Illinois and Rex Operating in this lawsuit. If, however, as a result of this lawsuit, we are required to pay significant monetary damages or settlement costs in excess of any insurance proceeds, our financial position and results of operations could be substantially harmed. (For more information regarding the putative class action lawsuit, please see "Item 3. Legal Proceedings.")

Our results of operations and cash flow may be adversely affected by risks associated with our oil and gas financial derivative activities, and our oil and gas financial derivative activities may limit potential gains.

We have entered into, and we expect to enter into in the future, oil and gas financial derivative arrangements corresponding to a significant portion of our oil and natural gas production. Many derivative instruments that we employ require us to make cash payments to the extent the applicable index exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in oil and natural gas prices. During the twelve months ended December 31, 2007, we incurred realized losses of $6,198,387 from our financial derivatives, which effectively reduces our total revenues from our oil and gas sales. Please read "Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations—Recently Adopted Accounting Pronouncements."

If our actual production and sales for any period are less than the corresponding volume of derivative contracts for that period (including reductions in production due to operational delays) or if we are unable to perform our activities as planned, we might be forced to satisfy all or a portion of our derivative obligations without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. In addition, our oil and gas financial derivative activities can result in

substantial losses. Such losses could occur under various circumstances, including any circumstance in which a counterparty does not perform its obligations under the applicable derivative arrangement, the arrangement is imperfect or our derivative policies and procedures are not followed or do not work as planned. Under the terms of our senior credit facility with KeyBank National Association, the percentage of our total production volumes with respect to which we will be allowed to enter into derivative contracts is limited, and we therefore retain the risk of a price decrease for our remaining production volume.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties, potentially triggering earlier-than-anticipated repayments of any outstanding debt obligations and negatively impacting the trading value of our securities.

There is a risk that we will be required to write down the carrying value of our oil and gas properties, which would reduce our earnings and stockholders' equity. We account for our natural gas and crude oil exploration and development activities using the successful efforts method of accounting. Under this method, costs of productive exploratory wells, developmental dry holes and productive wells and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and gas leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. The capitalized costs of our oil and gas properties may not exceed the estimated future net cash flows from our properties. If capitalized costs exceed future cash flows, we write down the costs of the properties to our estimate of fair market value. Any such charge will not affect our cash flow from operating activities, but it will reduce our earnings and stockholders' equity.

A write down could occur if oil and gas prices decline or if we have substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our drilling results. Because our properties currently serve, and will likely continue to serve, as collateral for advances under our existing and future credit facilities, a write-down in the carrying values of our properties could require us to repay debt earlier than we would otherwise be required. It is likely that the cumulative effect of a write-down could also negatively impact the value of our securities, including our common stock.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive but may actually deliver oil and gas in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature and an allocation of costs is required to properly account for the results. The evaluation of oil and gas leasehold acquisition costs requires judgment to estimate the fair value of these costs with reference to drilling activity in a given area.

We review our oil and gas properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value. Once incurred, a write down of oil and gas properties is not reversible at a later date even if gas or oil prices increase. Given the complexities associated with oil and gas reserve estimates and the history of price volatility in the oil and gas markets, events may arise that would require us to record an impairment of the recorded book values associated with oil and gas properties.

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

Our future success will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our

control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Please read "—Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves" for a discussion of the uncertainties involved in these processes. Our costs of drilling, completing and operating wells are often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures could be materially and adversely affected by any factor that may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- oil and natural gas property title problems; and
- market limitations for oil and natural gas.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves.

Estimates of oil and natural gas reserves are inherently imprecise. The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves. To prepare our estimates, we must project production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated oil and natural gas reserves. We base the estimated discounted future net cash flows from our proved reserves on prices and costs in effect on the day of estimate. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;
- the amount and timing of actual production;

- supply of and demand for oil and natural gas; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be 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.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Our prospects are in various stages of evaluation. There is no way to predict with certainty in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies, and the study of producing fields in the same area, will not enable us to know conclusively before drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercially viable quantities. Moreover, the analogies we draw from available data from other wells, more fully explored prospects or producing fields may not be applicable to our drilling prospects.

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

We do not operate all of the properties in which we own an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the 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 interests 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:

- nature and timing of drilling and operational activities;
- timing and amount of capital expenditures;
- expertise and financial resources;
- the approval of other participants in drilling wells; and
- selection of suitable technology.

If our access to markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. Our productive properties may be located in areas with limited or no access to pipelines, thereby necessitating delivery by other means, such as trucking, or requiring compression facilities. Such restrictions on our ability to sell our oil or natural gas may have several adverse affects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possibly causing us to lose a lease due to lack of production.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition and results of operations.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending on reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, results of operations and financial condition.

Our future acquisitions may yield revenues or production that vary significantly from our projections.

In acquiring producing properties, we will assess the recoverable reserves, future natural gas and oil prices, operating costs, potential liabilities and other factors relating to the properties. Our assessments are necessarily inexact and their accuracy is inherently uncertain. Our review of a subject property in connection with our acquisition assessment will not reveal all existing or potential problems or permit us to become sufficiently familiar with the property to assess fully its deficiencies and capabilities. We may not inspect every well, and we may not be able to observe structural and environmental problems even when we do inspect a well. If problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of those problems. Any acquisition of property interests may not be economically successful, and unsuccessful acquisitions may have a material adverse effect on our financial condition and future results of operations.

Our development and exploration operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration for, and development, production and acquisition of, oil and natural gas reserves. To date, we have financed capital expenditures primarily with proceeds from bank borrowings and cash generated by operations. We intend to finance our capital expenditures with the sale of equity, asset sales, cash flow from operations and current and new financing arrangements. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues decrease as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may need to seek additional financing in the future. In addition, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves. Also, our credit facility contains covenants that restricts our ability to, among other things, materially change our business, approve and distribute dividends, enter into transactions with affiliates, create or acquire additional subsidiaries, incur indebtedness, sell assets, make loans to others, make investments, enter into mergers, incur liens, and enter into agreements regarding swap and other derivative transactions.

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

With the increase in the prices of oil and natural gas during the past few years, we have encountered an increase in the cost of securing drilling rigs, equipment and supplies. Shortages or the high cost of drilling rigs, equipment, supplies and personnel are expected to continue in the near-term. In addition, larger producers may be more likely to secure access to such equipment by offering more lucrative terms. If we are unable to acquire access to such resources, or can obtain access only at higher prices, our ability to convert our reserves into cash flow could be delayed and the cost of producing those reserves could increase significantly, which would adversely affect our results of operation and financial condition.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations, and we may not have enough insurance to cover all of the risks that we face.

We maintain insurance coverage against some, but not all, potential losses 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, it is not possible to insure fully against pollution and environmental risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

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

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us. If a significant accident or other event occurs and is not fully covered by insurance, then that accident or other event could adversely affect our results of operations, financial condition and cash flows.

Our business may suffer if we lose key personnel.

Our operations depend on the continuing efforts of our executive officers and senior management. Our business or prospects could be adversely affected if any of these persons does not continue in his management role with us and we are unable to attract and retain qualified replacements. Additionally, we do not carry key person insurance for any of our executive officers or senior management.

We are subject to complex laws and regulations that can adversely affect the cost, manner or feasibility of doing business.

The exploration, development, production and sale of oil and natural gas are subject to extensive federal, state, and local laws and regulations. We may incur substantial expenditures to comply with these laws and regulations, which may require:

- discharge permits for drilling operations;
- drilling bonds;
- reports concerning operations;
- the spacing of wells;
- unitization and pooling of properties; and
- the payment of taxes.

Under these laws, we could be subject to claims for personal injury or property damages, including natural resource damages, which may result from the impacts of our operations. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws could change in ways that substantially increase our costs of compliance. Any such liabilities, penalties, suspensions, terminations or regulatory changes could have a material adverse effect on our financial condition and results of operations.

Our operations expose us to substantial costs and liabilities with respect to environmental matters.

Our oil and natural gas operations are subject to stringent federal, state and local laws and regulations governing the release 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 substances that can be released into the environment in connection with our drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, and impose substantial liabilities for pollution that may result from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of investigatory or remedial obligations or injunctive relief. Under existing environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether the release resulted from our operations, or our operations were in compliance with all applicable laws at the time they were performed. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance, and may otherwise have a material adverse effect on our results of operations, competitive position or financial condition.

Competition in the oil and natural gas industry is intense, which may adversely affect our ability to compete.

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

Being a public company has increased our expenses and administrative workload.

We completed our initial public offering in July 2007. As a public company, we must comply with various laws and regulations, including the Sarbanes-Oxley Act of 2002 and related rules of the Securities and Exchange Commission, or the SEC, and requirements of NASDAQ. We were not required to comply with all of these laws and requirements before our initial public offering. Complying with these laws and regulations requires the time and attention of our board of directors and management and increases our expenses. Among other things, we must:

- maintain and evaluate a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;
- maintain policies relating to disclosure controls and procedures;
- prepare and distribute periodic reports in compliance with our obligations under federal securities laws;
- institute a more comprehensive compliance function, including with respect to corporate governance; and
- involve to a greater degree our outside legal counsel and accountants in the above activities.

In addition, being a public company has made it more expensive for us to obtain director and officer liability insurance. In the future, we may be required to accept reduced coverage or incur substantially higher costs to obtain this coverage. These factors could also make it more difficult for us to attract and retain qualified executives and members of our board of directors, particularly directors willing to serve on our audit committee.

Risks Related to Our Common Stock

Our common stock has only been publicly traded since July 30, 2007 and the price of our common stock has fluctuated substantially since then and may fluctuate substantially in the future.

Our common stock has only been publicly traded since our initial public offering on July 30, 2007. The price of our common stock has fluctuated significantly since then. From July 30, 2007 to March 28, 2008, the closing trading price of our common stock ranged from a low of $7.75 per share to a high of $17.69 per share. We expect our stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include:

- changes in oil and natural gas prices;
- variations in quarterly drilling, recompletions, acquisitions and operating results;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- additions or departures of key personnel;
- future sales of our stock; or
- other factors discussed in the “Risk Factors” section and elsewhere in this report.

We may fail to meet expectations of our stockholders or of securities analysts at some time in the future, and our stock price could decline as a result.

You may experience dilution of your ownership interests due to the future issuance of additional shares of our common stock.

We may in the future issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of our present stockholders and purchasers of common stock offered hereby. We are

authorized to issue 100,000,000 shares of common stock and 100,000 shares of preferred stock with such designations, preferences and rights as may be determined by our board of directors. We may also issue additional shares of our common stock or other securities that are convertible into or exercisable for common stock in connection with the hiring of personnel, future acquisitions, future private placements of our securities for capital raising purposes or for other business purposes. Future sales of substantial amounts of our common stock, or the perception that sales could occur, could have a material adverse effect on the price of our common stock.

Our certificate of incorporation, bylaws and Delaware law contain provisions that could make it more difficult for a third party to acquire us without the consent of our board of directors and our Chairman and other executive officers, which collectively beneficially own approximately 52% of the outstanding shares of our common stock as of March 31, 2008.

Provisions in our certificate of incorporation and bylaws will have the effect of delaying or preventing a change of control or changes in our management. These provisions include the following:

- The ability of the board to issue shares of our common stock and preferred stock without stockholder approval;
- The ability of our board of directors to make, alter or repeal our bylaws without further stockholder approval;
- The requirement for advance notice for nominations for directors to our board of directors and for proposing matters that can be acted upon by stockholders at stockholder meetings; and
- Stockholders may not take action by written consent.

In addition, we are subject the provisions of Section 203 of the Delaware General Corporation Law. These provisions may prohibit large stockholders, in particular those owning 15% or more of our outstanding voting stock, from merging or combining with us.

In addition, Lance T. Shaner, our Chairman, beneficially owns approximately 41%, and our other executive officers collectively own approximately 11%, of the outstanding shares of our common stock. As a result, these stockholders, acting together, will have the ability to exert substantial influence over all matters requiring approval by our stockholders, including the election and removal of directors, any proposed merger, consolidation or sale of all or substantially all of our assets and other corporate transactions.

These provisions in our certificate of incorporation and bylaws and under Delaware law, and this concentrated ownership of our common stock by our Chairman and executive officers could discourage potential takeover attempts and could reduce the price that investors might be willing to pay for shares of our common stock.

Because we have no plans to pay dividends on our common stock, stockholders must look solely to appreciation of our common stock to realize a gain on their investments.

We do not anticipate paying any dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our business, financial condition, results of operations, capital requirements and investment opportunities. In addition, our senior credit facility limits the payment of dividends without the prior written consent of the lenders. Accordingly, stockholders must look solely to appreciation of our common stock to realize a gain on their investment. This appreciation may not occur.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

The table below summarizes certain data for our core operating areas for the year ended December 31, 2007:

Division	Average Daily Production (BOE per day)	Total Production (BOE)	Percentage of Total Production	Total Proved Reserves (BOE)	Percentage of Total Proved Reserves
Illinois Basin	2,109	769,911	76.4%	11,962,181	75.4%
Appalachian Basin	359	131,016	13.0%	2,119,316	13.3%
Southwestern Region	294	107,263	10.6%	1,786,162	11.3%
Totals	2,762	1,008,190	100.0%	15,867,659	100.0%

Segment reporting is not applicable to us as we have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

Illinois Basin

In the Illinois Basin, we own 2,017 net wells, 99% of which we operate. We have approximately 356,000 gross (116,000 net) acres under lease, which includes our interests in the Lawrence Field and New Albany Shale.

Total proved reserves increased approximately 1.2 MMBOE, or 11%, to approximately 12.0 MMBOE at December 31, 2007, when compared to year-end 2006. Annual production increased 41% over 2006. Capital expenditures in 2007 for developmental drilling and facility improvements in the region were approximately $14.8 million, which funded the drilling of 32 gross (31.8 net) development wells, of which 23 gross (22.9 net) were productive and 9 gross (8.9 net) were expected to be completed and producing during the first quarter of 2008. Capital expenditures in 2007 also funded the recompletion of 12 gross (11.9 net) recompletions. Additionally, in the Illinois Basin, capital expenditures for drilling and facilities development for the New Albany Shale project totaled approximately $3.2 million, which funded the drilling of 8 gross (2 net) exploratory wells. These wells are currently under evaluation to determine if they will be economical to produce. Capital expenditures for drilling and facilities development for the Lawrence Field ASP Flood Project in Lawrence County, Illinois totaled approximately $5.5 million, of which approximately $4.1 funded facilities development and the remaining $1.4 million funded the drilling or recompletion of 10 gross (10 net) exploratory producer wells and 7 gross (7 net) exploratory injector wells.

At December 31, 2007, the Illinois Basin had a development inventory of 216 proven drilling locations and 172 proven recompletions. Development projects include recompletions, infill drilling and continued refinement of secondary recovery operations. These activities also include increasing reserves and production through aggressive cost control, upgrading lifting equipment, improving gathering systems and surface facilities and performing restimulations and refracturing operations.

Lawrence Field ASP Flood Project

We are implementing an ASP flood project in the Cypress and Bridgeport Sandstone reservoirs of our Lawrence Field acreage. The Lawrence Field ASP Flood Project is one of our largest projects. The Lawrence Field ASP Flood Project is considered an EOR project, which refers to recovery of oil that is not producible by primary or secondary recovery methods.

The Lawrence Field in Lawrence County, Illinois, is believed to have produced more than 400 million barrels of oil from 23 separate horizons since its discovery in 1906. We currently own and operate 21.2 square

miles (approximately 13,500 net acres) of the Lawrence Field and our properties account for approximately 85% of the current total gross production from the field. The Cypress (Mississippian) and the Bridgeport (Pennsylvanian) sandstones are the major producing horizons in the field. To date, approximately 40% of the estimated one billion barrels of original oil in place has been produced.

In the 1960s, 1970s and 1980s, a number of EOR projects using surfactant polymer floods were implemented in several fields in the Illinois Basin by Marathon Oil Corp. ("Marathon"), Texaco and Exxon in an attempt to recover a portion of the large percentage of the original oil in place that was being bypassed by the secondary recovery waterflood. These test projects reportedly were able to recover incremental oil reserves of 15% to 30% of the original oil in place.

In 1982, Marathon began a surfactant polymer flood project in the Lawrence Field on the Robins Lease, a 25-acre lease in the Lawrence Field within one mile of the site of one of our pilot test locations. This project was initiated at a time when the price per barrel of oil was below $15 and the technology of combining alkali and surfactant with polymer, which significantly reduces costs of recovery compared with the previous surfactant polymer floods, had not yet been fully developed. Despite the high costs of the surfactant polymer flooding employed by Marathon and the low oil prices, the project produced an estimated 450,000 incremental barrels, or an estimated 21% the of original oil in place. While we believe the results of this project are pertinent, there can be no assurance that our Lawrence Field ASP Flood Project, which uses technology that was not developed at the time of the Robins Lease flood, will achieve similar results.

ASP technology, which uses similar mechanisms to mobilize bypassed residual oil as these previous surfactant polymer floods but at significantly lower costs, has been applied by other companies in several fields around the world resulting in significant incremental recoveries of the original oil in place. Chemicals used in the Lawrence Field ASP Flood Project are an alkali (NaOH or Na2CO3), a surfactant and a polymer. The alkali (1% to 2%) and surfactant (0.1% to 0.4%) combination washes residual oil from the reservoir mainly by reducing interfacial tension between the oil and the water. The polymer (800 to 1400 parts per million) is added to improve sweep displacement efficiency. ASP technology achieves its incremental recovery by reducing capillary forces that trap oil, improving aerial and vertical sweep efficiency and reducing mobility ratio.

Our Lawrence Field ASP Flood Project will use ASP technology to flood our Lawrence Field wells. The goal of our Lawrence Field ASP Flood Project is to duplicate the oil recovery performance of the surfactant polymer floods conducted in the field in the 1980s, but at a significantly lower cost. We expect this cost reduction to be accomplished by utilizing newer technologies to optimize the synergistic performance of the three chemicals used, and by using alkali in the formula, which would allow us to use a significantly lower concentration of the more costly surfactant.

In 2000, PennTex Illinois, then known as Plains Illinois, Inc., and the U.S. Department of Energy conducted a study on the potential of an ASP project in the Lawrence Field with consulting services provided by Surtek, Inc. ("Surtek"), an independent engineering firm specializing in the design and implementation of chemical oil recovery systems. Based on modeling of the reservoir characteristics and laboratory tests with cores taken in the Lawrence Field, the evaluation found oil recovery in the field could be increased significantly by installing an ASP flood. Similar EOR techniques have been successfully demonstrated in fields around the world to recover an additional 15% to 30% of the original oil in place. However, there can be no assurance that our Lawrence Field ASP Flood Project will achieve similar results.

In 2006, we engaged Surtek to review and update the evaluation on the application of the ASP process to the Lawrence Field. This evaluation, based on laboratory results, recommended two pilot areas to evaluate the ASP process in the Bridgeport and Cypress sandstones. The ASP pilot test locations are positioned in areas that we believe are representative of variabilities that can be expected in these reservoirs. Based on Surtek's recommendations, we drilled and cored the central producing well in each of the two proposed pilot test areas. These cores were sent to Surtek for ASP chemical system design. During 2007, Surtek completed their linear and

radial core flood analysis on the Cypress and Bridgeport sandstones, which in the laboratory, resulted in an oil recovery rate as high as 21% of the estimated original oil-in-place in the Cypress sandstone, and 24% of the original oil-in-place in the Bridgeport sandstone. These results were in line with our initial projections.

During 2006 and 2007, we drilled 18 wells in our two pilot areas, upgraded the pilot area production facilities, installed the production flow-lines to both pilot areas, installed the pilot injection pipelines, and began construction of the pilot area chemical injection plant. We plan to initiate injection of the ASP chemicals on the two pilots in the second quarter of 2008. If either of these two pilots is successful, we plan to implement a broad ASP flood program within the 13,500 net acres of the field that we currently own and operate, commencing in 2009. While we are encouraged by initial laboratory results, our Lawrence Field ASP Flood Project is not a proved project nor are any of the potential reserves from this project considered proved at this time.

New Albany Shale

As of December 31, 2007, we had acquired, over 306,000 gross (92,000 net) acres in southern Indiana that we believe to be prospective for New Albany Shale development. The New Albany Shale is predominantly an organic-rich black shale that is present in the subsurface throughout the Illinois Basin. Where the stratigraphy is known, the gas reservoirs are observed to be in the organic-rich black shales of the Grassy Creek (Shale), Clegg Creek, and Blocher (Shale) Members. Natural fractures are believed to provide the effective reservoirs permeability in these zones and gas is stored both as free gas in fractures and as adsorbed gas on kerogen and clay surfaces. Although limited gas production from vertical wells in the New Albany Shale has occurred for many years, interest in the potential of the New Albany Shale has recently increased due to the application of horizontal drilling techniques which can intersect numerous vertical fractures, significantly increasing the amount of reservoir contacted by each wellbore.

Since February 2006, we have participated in 11 gross New Albany Shale wells, four of which we operate, in Greene County and Knox County, Indiana. Of these wells, three wells drilled in 2006 were determined to be uneconomical and were expensed as dry holes in the fourth quarter of 2007, two have been tested and are awaiting pipeline connections, and six are still being evaluated to determine whether they will be economical to complete and produce and to design stimulation procedures, if required.

Appalachian Basin

As of December 31, 2007, we own approximately 557 gross producing natural gas wells in the Appalachian Basin, predominantly in Pennsylvania. These wells are characterized as shallow, predominantly drilled on 40 acre spacing at depths less than 5,000 feet, natural gas wells which have historically been long-life shallow decline reserves. In addition to our producing wells in the basin, we own 44 proved undeveloped drilling locations with total reserves of 4.6 Bcf, and three locations with proved developed non-producing reserves totaling 177 MMcf. At December 31, 2007, we had approximately 70,000 gross (33,000 net) acres in the Appalachian Basin under lease, of which 35,000 gross (18,000 net) acres were undeveloped.

Reserves at December 31, 2007 increased 2.4 Bcf, or 24%, from 2006 due primarily to drilling additions which were partially offset by a net unfavorable reserve revision and production. Annual production increased 11% over 2006. Capital expenditures in 2007 for drilling and facility development in the region were approximately $5.2 million, which funded the drilling of 24 gross (14 net) development wells, of which 21 gross (12 net) were productive and three gross (two net) were expected to be completed and producing during the first quarter of 2008. During 2007, the region achieved a 100% drilling success rate.

Marcellus Shale

A large portion of our property in Pennsylvania is located in areas where active exploration for the Marcellus Shale, by companies such as Range Resources Corporation (NYSE:RRC), Equitable Resources, Inc.

(NYSE:EQT), EOG Resources, Inc. (NYSE:EOG) and Atlas Energy Resources, LLC (NYSE: ATN), is occurring with encouraging results. The Marcellus Shale is a black, organic rich shale formation located at depths between 7,000 and 8,500 feet and ranges in thickness from 75 to 150 feet on our acreage in southwestern and central Pennsylvania. As of December 31, 2007 we had interests in approximately 44,000 gross (21,000 net) Marcellus Shale prospective acres in these areas of Pennsylvania, and we continue to expand our position. As of March 20, 2008, we increased our position to approximately 60,000 gross (30,000 net) Marcellus Shale prospective acres in these areas of Pennsylvania. During 2008, we plan to begin testing our acreage in these areas and to continue to expand our acreage positions in this emerging play. As of December 31, 2007, we had not yet completed any wells and have not booked any proved reserves in the Marcellus Shale.

Southwestern Region

Our operations in our Southwestern region include several producing oil and gas fields in Lea and Eddy Counties, New Mexico, Terrell County, Texas and other producing regions of western Texas. At December 31, 2007, we operated 93 wells, and owned interests in another 59 wells, in west Texas and southeast New Mexico. At December 31, 2007, we had approximately 15,000 gross (10,000 net) acres in the Southwestern region under lease, of which approximately 1,900 gross (1,500 net) acres were undeveloped.

Reserves decreased approximately 200 MBOE, or 10%, in 2007. On an annual basis, production decreased approximately 1% from 2006. Capital expenditures in 2007 for drilling and facility development in the region totaled approximately $4.0 million, which funded the drilling of one gross (.8 net) development wells, and three gross (three net) exploratory wells, of which, one gross (one net) was expensed as a dry hole in 2007 and two gross (two net) were still being evaluated to determine if they would be economical to produce at year end. Capital expenditures in 2007 also funded the recompletion of 11 gross (8.8 net) wells. At December 31, 2007, the Southwestern region had a development inventory of eight proven drilling locations and three proven recompletions.

Proved Reserves

Netherland, Sewell & Associates, Inc., an independent petroleum engineering firm, evaluated our reserves on a consolidated basis as of December 31, 2007. All of our reserves are located within the continental United States. Reserve estimates are inherently imprecise and remain subject to revisions based on production history, results of additional exploration and development, prices of oil and natural gas and other factors. Please read "Item 1A—Risk Factors—Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves." You should also read the notes following the table below and our consolidated and combined financial statements for the year ended December 31, 2007 in conjunction with the following reserve estimates. We did not file any reports during the year ended December 31, 2007 with any federal authority or agency with respect to our estimates of oil and natural gas reserves.

The following table sets forth our estimated proved reserves at the end of each of the past three years:

	December 31, 2007	2006	2005
Estimated Proved Reserves(1)			
Gas (Bcf)	18.5	17.2	16.1
Oil (MMBbls)	12.8	11.6	6.4
Total proved reserves (MMBOE)(2)	15.9	14.5	9.1
PV-10 Value (millions)(3)	$392.1	$200.3	$148.1
Pro Forma Standardized Measure (millions)(4)	$255.0	$132.1	$108.2

(1) The estimates of reserves in the table above conform to the guidelines of the SEC. Estimated recoverable proved reserves have been determined without regard to any economic impact that may result from our financial derivative activities. These calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry. The estimated present value of proved reserves does not give effect to indirect expenses such as debt service and future income tax expense, asset retirement obligations or to depletion, depreciation and amortization. The reserve information shown is estimated. The accuracy of any reserve estimate is a function of the quality of available geological, geophysical, engineering and economic data, the precision of the engineering and geological interpretation and judgment. The estimates of reserves, future cash flows and present value are based on various assumptions, and are inherently imprecise. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates. Also, the use of a 10% discount factor for reporting purposes may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject.

(2) We converted natural gas to barrels of oil equivalent at a ratio of one barrel to six Mcf.

(3) Represents the present value, discounted at 10% per annum (PV-10), of estimated future cash flows before income tax of our estimated proved reserves. The estimated future cash flows set forth above were determined by using reserve quantities of proved reserves and the periods in which they are expected to be developed and produced based on economic conditions prevailing at December 31, 2007. The estimated future production is priced at December 31, 2007, without escalation, using $92.50 per bbl and $6.795 per MMBtu and adjusted by lease for transportation fees and regional price differentials. Management believes that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. For an explanation of why we show PV-10 and a reconciliation of PV-10 to the standardized measure of discounted future net cash flow, please read “Selected Historical Financial and Operating Data—Non-GAAP Financial Measures.” Please also read “Risk Factors—Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves.”

(4) Because each of the Predecessor Companies was a flow-through entity for state and federal tax purposes, our historical standardized measure for the years 2005 and 2006 does not deduct state or federal taxes. This differs from our pro forma standardized measure, which deducts state and federal taxes.

Acreage and Productive Wells Summary

The following table sets forth our gross and net acres of developed and undeveloped oil and natural gas leases and our gross and net productive oil and natural gas wells as of December 31, 2007:

	Undeveloped Acreage(1)		Developed Acreage(2)		Total Acreage		Producing Gas Wells		Producing Oil Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Appalachian Basin										
Pennsylvania	34,610	18,115	35,218	15,045	69,828	33,160	425(3)	186	—	—
Illinois Basin										
Illinois	12,752	4,481	34,580	19,476	47,332	23,957	—	—	1,180	1,173
Indiana	293,681	79,987	12,455	11,685	306,136	91,672	—	—	221	216
Kentucky	1,244	474	821	28	2,065	502	—	—	—	—
Total Illinois Basin	307,677	84,942	47,856	31,189	355,533	116,131	—	—	1,401	1,389
Southwestern Region										
Texas	1,440	1,160	9,199	6,245	10,639	7,405	21	7	43	40
New Mexico	437	326	4,320	1,902	4,757	2,228	35	7	16	4
Total Southwestern Region	1,877	1,486	13,519	8,147	15,396	9,633	56	14	59	44
Total	344,164	104,543	96,593	54,381	440,757	158,924	481	200	1,460	1,433

(1) Undeveloped acreage is 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 includes proved reserves.
(2) Developed acreage is the number of acres that are allocated or assignable to producing wells or wells capable of production.
(3) In addition, we own royalty interests in approximately 132 natural gas wells in the Appalachian Basin.

Substantially all of the leases summarized in the preceding table will expire at the end of their respective primary terms unless the existing lease is renewed or we have obtained production from the acreage subject to the lease before the end of the primary term, in which event the lease will remain in effect until the cessation of production.

The following table sets forth the gross and net acres of undeveloped land subject to leases summarized in the preceding table that will expire during the periods indicated:

	Expiring Acreage	
	Gross	Net
Year Ending December 31,		
2008	17,282	4,416
2009	76,401	20,518
2010	127,715	39,436
2011	79,439	22,241
Thereafter	27,781	12,242
Total	328,618	98,853

Drilling Results

The following table summarizes drilling activity for the past three years. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells. All of our drilling activities are conducted on a contract basis by independent drilling contractors. We own six workover rigs which are used in our Illinois Basin operations. We do not own any drilling equipment.

	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Illinois Basin	32.0	31.8	24.0	23.9	3.0	1.5
Appalachian Basin	24.0	13.7	31.0	11.4	30.0	9.3
Southwestern Region	1.0	0.8	2.0	0.3	—	—
Non-Productive	—	—	3.0	2.1	1.0	0.1
Total Development wells	57.0	46.3	60.0	37.7	34.0	10.9
Exploratory wells:						
Illinois Basin	25.0	19.0	2.0	1.2	—	—
Appalachian Basin	—	—	—	—	—	—
Southwestern Region	2.0	2.0	—	—	—	—
Non-Productive	1.0	1.0	6.0	1.3	—	—
Total Exploratory wells	28.0	22.0	8.0	2.5	—	—
Total wells	85.0	68.3	68.0	40.2	34.0	10.9
Success ratio	98.8%	98.5%	86.7%	91.5%	97.1%	99.1%

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often minimal investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include:

- customary royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- development obligations under oil and gas leases; or
- net profit interests.

ITEM 3. LEGAL PROCEEDINGS

General

From time to time, we may be involved in litigation relating to claims arising out of our operations in the normal course of business. Except as described below, we do not believe we are party to any legal proceedings, which, if determined adversely to us, individually or in the aggregate, would have a material adverse effect on our financial position, results of operations or cash flows.

PennTex Illinois and Rex Operating—EPA Enforcement Matter

In September 2006, the United States Department of Justice ("U.S. DOJ") and the United States Environmental Protection Agency ("U.S. EPA") initiated an enforcement action against PennTex Illinois and

Rex Operating seeking mandatory injunctive relief and potential civil penalties based on allegations that the companies were violating the Clean Air Act in connection with the release of hydrogen sulfide (H_2S) gas and other volatile organic compounds ("VOC's") in the course of the companies' oil producing operations near the towns of Bridgeport, Illinois and Petrolia, Illinois. The companies' senior management and representatives of the U.S. EPA, U.S. DOJ, Illinois Environmental Protection Agency ("Illinois EPA") and the Agency for Toxic Substances and Disease Registry ("ATSDR") attended a meeting at the offices of the U.S. EPA in Chicago, Illinois on September 7, 2006, to discuss matters relating to the enforcement action. This meeting had been preceded by certain monitoring of air emissions in the areas surrounding Bridgeport, Illinois and Petrolia, Illinois that the U.S. EPA and ATSDR had conducted in May 2006.

As a result of the initial meeting with the government on September 7, 2006, and certain subsequent meetings and communications with the U.S. EPA and U.S. DOJ, PennTex Illinois and Rex Operating executed a non-binding agreement in principle with the U.S. EPA effective October 24, 2006. In the agreement in principle, PennTex Illinois and Rex Operating agreed to develop and carry out a written response plan designed to further reduce possible emissions of H_2S and VOC's from the companies' oil wells and facilities in the Lawrence Field that are closest to populated areas. The companies agreed to operate and maintain the control measures described in the response plan in accordance with a written operations and maintenance plan to be developed by the companies and approved by the U.S. EPA. The agreement in principle also required the companies to evaluate the effectiveness of the control measures in the Lawrence Field installed pursuant to the response plan through a monitoring program, and required them to evaluate the need for additional control measures at other facilities within the Lawrence Field within 60 days. The companies also agreed to present to the U.S. EPA any recommendations for further action the companies might develop based upon their observations of the effectiveness of the control measures. The parties each agreed that they would use their best efforts to negotiate a proposed final settlement agreement that would resolve the government's enforcement action, which settlement agreement would be published in the Federal Register and made subject to public comment before any final approval.

On April 4, 2007, PennTex Illinois, Rex Operating and the U.S. EPA and U.S. DOJ executed a comprehensive consent decree in which PennTex Illinois and Rex Operating, without any admission of wrongdoing or liability and without any agreement to pay any civil fine or penalty, agreed to install certain control measures and to implement certain operating and maintenance procedures in the Lawrence Field. Under the terms of the proposed consent decree, PennTex Illinois and Rex Operating agreed to establish a monitoring protocol that would be designed to facilitate the reduction of possible emissions of H_2S and VOCs from PennTex Illinois' operations near Bridgeport and Petrolia. A notice regarding the proposed consent decree was published in the Federal Register on April 19, 2007. The published notice of the proposed consent decree solicited public comments on the terms of the consent decree for a 30 day period expiring on May 21, 2007. The United States did not receive any comments on the proposed consent decree during the public comment period. On June 1, 2007, the United States filed a motion for the approval and entry of the proposed consent decree with the United States District Court for the Southern District of Illinois. On June 6, 2007, the court granted the United States' motion for approval and entry of the proposed consent decree, thereby resolving the enforcement action according to the terms described in the consent decree. The consent decree does not require us to pay any civil fine or penalty, although it does provide for the possible imposition of specified daily fines and penalties for any violation of the terms and conditions of the consent decree.

As of December 31, 2007, we have substantially met all requirements of the consent decree. In a letter dated February 8, 2008, the U.S. EPA, in consultation with the Illinois EPA, approved our proposed plan and schedule for implementing our H_2S control measures in the Lawrence Field. We will be installing these additional controls throughout 2008, with an expected completion date of December 31, 2008.

PennTex Illinois and Rex Operating – H2S Putative Class Action Litigation

PennTex Illinois and Rex Operating are defendants in a putative class action lawsuit that has been filed in the United States District Court for the Southern District of Illinois. This action was commenced on October 17,

2006, by plaintiffs Julia Leib and Lisa Thompson, individually and as putative class representatives on behalf of all persons and non-governmental entities that own property or reside on property located in the towns of Bridgeport and Petrolia, Illinois. The complaint asserts that the operation of oil wells that are controlled, owned or operated by PennTex Illinois and Rex Operating has resulted in "serious contamination" of the class area with H_2S. The complaint asserts several causes of action, including violation of the Illinois Environmental Protection Act, negligence, private nuisance, trespass, and willful and wanton misconduct. The complaint was amended in March 2007 to add a claim for alleged violation of Section 7002(a)(1) of the Resource Conservation And Recovery Act. The complaint seeks, among other things, injunctive relief under the Illinois Environmental Protection Act and Illinois common law, compensatory and other damages, punitive damages, and attorneys' fees and costs. In addition, the complaint seeks the creation of a court-supervised, defendant-financed fund to pay for medical monitoring for the plaintiffs and others in the class area. PennTex Illinois and Rex Operating have filed a joint answer to the amended complaint denying virtually all of the allegations in the amended complaint and asserting affirmative defenses thereto.

On December 20, 2006, the plaintiffs filed a motion for class certification requesting that the court certify the case as a class action. On January 26, 2007, the court issued a scheduling and discovery order establishing deadlines for completing discovery and briefing relating to the plaintiffs' motion for class certification. The original order provided for an August 2007 deadline for the completion of pre-certification discovery and the filing of the last brief on class certification issues; however, in August 2007, and again in October 2007, the scheduling and discovery order was amended to extend these deadlines to January 2008.

The plaintiffs filed an amended motion for class certification on January 22, 2008. PennTex Illinois and Rex Operating filed a joint motion opposing class certification on February 22, 2008 and the plaintiffs filed a reply brief on March 20, 2008. The current scheduling and discovery order issued by the court provides that the court may schedule a hearing on class certification if it deems that one is necessary.

The parties to this lawsuit have exchanged initial pretrial disclosures as required under the applicable rules, and each side has served and responded to pre-deposition written discovery. In addition, we have deposed each of the named plaintiffs and each of plaintiffs' expert witnesses offered in support of plaintiffs' motion for class certification. The plaintiffs did not elect to depose our expert witnesses offered in support of our opposition to class certification. The final pretrial conference for this case is scheduled for August 7, 2008. The case is scheduled for jury trial on August 18, 2008, in the United States District Court for the Southern District of Illinois located in Benton, Illinois.

We believe that there is no evidence that any H_2S gas emissions from any of our facilities have caused any damage or injury to any person or property, and we intend to vigorously defend against the claims that have been asserted against PennTex Illinois and Rex Operating in this lawsuit. Because this lawsuit is in its initial stages regarding the issue of class certification, however, and because it is usually difficult to predict the outcome of litigation, we are unable to express an opinion with respect to the likelihood of an unfavorable outcome or to estimate the amount or the range of potential loss should the outcome be unfavorable to us.

Pursuant to the terms of a pollution liability policy with Federal Insurance Company, we have insurance coverage for possible damages relating to claims made in this lawsuit for up to $1,000,000. In addition, in accordance with the terms of the pollution liability policy, Federal Insurance Company has agreed to conduct our defense in this lawsuit at the insurer's expense. Under the terms of a written agreement with us, Federal Insurance Company has agreed to pay a substantial portion of our costs and expenses relating to the defense of this lawsuit, including attorneys' fees. Under the terms of our agreement, we are required to pay the costs and expenses relating to the defense in excess of the amounts payable by Federal Insurance Company.

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

Not applicable.

PART II

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

We completed the initial public offering of our common stock on July 30, 2007. Since that time, our common stock has been quoted on NASDAQ under the symbol “REXX”. Before then, there was no public market for our common stock. As of March 28, 2008, there were approximately 246 holders of record of our common stock.

The following table sets forth, for the periods indicated, the range of the daily high and low sale prices for our common stock as reported by NASDAQ.

2007	High	Low
Third quarter	10.45	7.75
Fourth quarter	11.93	8.25

Dividends

We have not paid cash dividends on our common stock since our inception in July 2007. We do not anticipate paying any dividends on the shares of our common stock in the foreseeable future. We currently intend to reinvest our earnings to finance the expansion of our business. In addition, the terms of our senior credit facility restricts our ability to pay cash dividends to holders of our common stock.

Issuer Purchases of Equity Securities

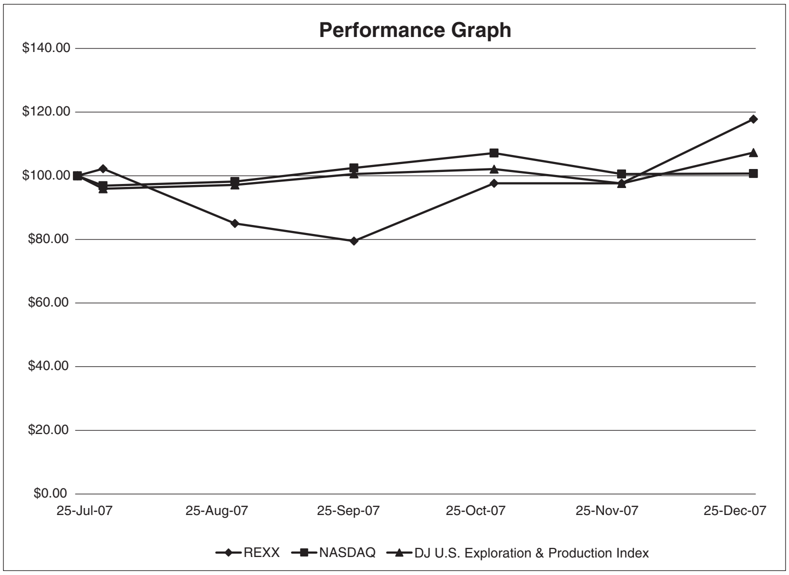
We do not have a stock repurchase program for our common stock.

Use of Proceeds from Public Offering of Common Stock

On July 30, 2007, we completed our initial public offering of 8,800,000 shares of our common stock pursuant to a registration statement on Form S-1 (Registration No. 333-142430), which the U.S. Securities and Exchange Commission declared effective on July 25, 2007. KeyBanc Capital Markets Inc. acted as lead manager for the offering. RBC Capital Markets, A.G. Edwards, Johnson Rice & Company L.L.C. and Pickering Energy Partners acted as co-managers for the offering. As a result of the initial public offering, we raised approximately $87.9 million in net proceeds to us after deducting underwriting discounts and commissions of $5.8 million, offering expenses of $2.6 million, and a structuring fee of $484,000 paid by us to KeyBanc Capital Markets Inc. We used all of the proceeds from the initial public offering to repay all outstanding indebtedness under credit facilities of the Predecessor Companies with the exception of the Rex IV line of credit.

Performance Graph

The following graph presents a comparison of the yearly percentage change in the cumulative total return on our common stock over the period from July 25, 2007, the date our common stock was first publicly-traded, to December 31, 2007, with the cumulative total return of the NASDAQ Global Market Index and the Dow Jones U.S. Oil and Gas Exploration and Production Index of publicly traded companies over the same period. The graph assumes that $100 was invested on July 25, 2007 in our common stock at the closing market price at the beginning of this period and in each of the other two indices and the reinvestment of all dividends, if any. This historic stock price performance is not necessarily indicative of future stock performance.



	S&P	Dow Jones	Rex Energy
July 25, 2007	$100	$100	$100
December 31, 2007	$101	$107	$118

* The performance graph and the information contained in this section is not "soliciting material," is being "furnished" not "filed" with the SEC and is not to be incorporated by reference into any of our filings under the Securities Act or the Exchange Act whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing.

ITEM 6. SELECTED FINANCIAL AND OPERATING DATA

Summary Financial Data

The following table shows selected consolidated and combined financial data of Rex Energy Corporation and the Predecessor Companies for each of the periods indicated. The historical consolidated and combined financial data has been prepared for Rex Energy Corporation for the year ended December 31, 2007. The historical combined financial data has been prepared for the Predecessor Companies for the years ended December 31, 2006, 2005, 2004, and 2003. The historical consolidated and combined financial statements for the years ended December 31, 2007, 2006, 2005 and 2004 are derived from the historical audited financial data of Rex Energy Corporation and the Predecessor Companies. The historical combined financial statements for the year ended December 31, 2003 is derived from the historical unaudited financial data of the Predecessor Companies. All material intercompany balances and transactions have been eliminated. Because each of the Predecessor Companies was taxed as a partnership for each of the periods indicated for federal and state income tax purposes, the following statements make no provision for income taxes for the years ended December 31, 2006, 2005, 2004, and 2002 and the seven month period ended July 31, 2007. Provision for income tax is presented for the five month period ended December 31, 2007. This information should be read in conjunction with Item 7 of this report "Management's Discussion and Analysis of Financial Condition and Results of Operations," and our consolidated and combined financial statements and related notes as of December 31, 2007 and 2006 and for each of the years ended December 31, 2007, 2006 and 2005, included elsewhere in this report. These selected combined historical financial results may not be indicative of our future financial or operating results.

The following table includes the non-GAAP financial measure of EBITDAX. For a definition of EBITDAX and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please see "—Non-GAAP Financial Measures."

	Rex Energy Corporation Consolidated and Combined	Rex Energy Combined Predecessor Companies	Rex Energy Combined Predecessor Companies	Rex Energy Combined Predecessor Companies	Rex Energy Combined Predecessor Companies
		Year Ended December 31, ($ and shares in Thousands)			
	2007	2006	2005	2004	2003
					(unaudited)
Statement of operations data:					
Operating Revenue:					
Oil and Gas Sales	$ 63,525	$43,596	$29,518	$14,159	$5,193
Other Revenue	452	470	270	697	928
Realized Gain (Loss) from Derivatives	(6,198)	(4,436)	(7,930)	(942)	—
Total Operating Revenue	57,779	39,630	21,858	13,914	6,121
Operating Expenses:					
Production Lease Operating and Production Taxes	24,477	15,234	11,721	6,708	2,204
General and Administrative	8,587	6,212	3,789	2,229	1,177
Depletion, Depreciation, Amortization and Accretion	19,622	11,223	3,320	2,039	1,015
Exploration	2,948	—	107	3,024	—
Total Operating Expenses	55,634	32,669	18,937	14,000	4,396
Income (Loss) from Operations	2,145	6,961	2,921	(86)	1,725
Other Income (Expenses):					
Interest Income	15	94	444	19	42
Interest Expense	(5,646)	(6,110)	(1,697)	(867)	(171)
Gain on Sale or Disposal of Oil and Gas Properties	185	91	1,016	659	—
Unrealized Gain (Loss) from Derivatives	(26,250)	5,043	(5,541)	(1,396)	—
Other Income (Expense)	171	(132)	216	(21)	—
Total Other Income (Expense)	(31,525)	(1,014)	(5,562)	(1,606)	(129)
Net Income (Loss) Before Minority Interests and Income Tax	(29,380)	5,947	(2,641)	(1,692)	1,596
Minority Interests Share of (Net Income) Loss	6,152	(2,133)	(2,304)	2,062	(968)
Income Tax Benefit (Expense)	7,017	—	—	—	—
Net Income (Loss)	$(16,211)	$ 3,814	$ (4,945)	$ 370	$ 628
Earnings per common share for the five month period ended December 31, 2007:					
Net loss for the five month period ended December 31, 2007	$(10,640)				
Basic and Fully Diluted earnings per common share	$ (0.35)	$ —	$ —	$ —	$ —
Weighted average shares of common stock outstanding	30,795	—	—	—	—

	Year Ended December 31, ($ in Thousands)				
	2007	2006	2005	2004	2003
					(unaudited)
Other Financial Data:					
EBITDAX (Before Minority Interests)	$ 25,282	$ 18,143	$ 7,580	$ 5,615	$ 804
Cash Flow Data:					
Cash provided by operating activities	17,555	12,920	9,527	5,983	631
Cash used by investing activities	(40,102)	(94,446)	(19,404)	(9,612)	(6,090)
Cash provided (used) by financing activities	23,032	79,438	9,772	5,457	5,913
Balance Sheet Data:					
Cash and cash equivalents	1,085	600	3,188	3,217	1,347
Property and Equipment (net of accumulated depreciation)	217,532	133,631	42,265	24,573	15,826
Total Assets	268,264	144,611	55,291	33,311	19,507
Current Liabilities, including current portion of long-term debt	20,736	53,684	32,297	13,672	2,864
Long-Term Debt, net of current maturities	27,207	45,442	3,360	3,000	4,259
Total Liabilities	103,827	108,639	42,080	18,416	7,611
Minority Interests	—	36,589	24,130	11,696	9,561
Owners' Equity	164,437	(617)	(10,920)	3,198	2,336

Summary Operating and Reserve Data

The following table summarizes our operating and reserve data as of and for each of the periods indicated. The following table includes the non-GAAP financial measure of PV-10. For a definition of PV-10 and a reconciliation to the standardized measure of discounted future net cash flow, its most directly comparable financial measure calculated and presented in accordance with GAAP, please see "—Non-GAAP Financial Measures."

	Year Ended December 31, ($ in Thousands)		
	2007	2006	2005
Production			
Oil (Bbls)	814,857	587,470	378,954
Natural gas (Mcf)	1,159,999	1,109,494	1,124,743
Oil equivalent (BOE)	1,008,190	772,386	566,411
Oil and natural gas sales(1)			
Oil sales	$ 55,542	$ 35,790	$ 20,355
Natural gas sales	7,983	7,806	9,163
Total	$ 63,525	$ 43,596	$ 29,518
Average sales price(1)			
Oil ($ per Bbl)	$ 68.16	$ 60.92	$ 53.71
Natural gas ($ per Mcf)	$ 6.88	$ 7.04	$ 8.15
Oil equivalent ($ per BOE)	$ 63.01	$ 56.44	$ 52.11
Average production cost			
Oil equivalent ($ per BOE)	$ 24.28	$ 19.72	$ 20.70
Estimated proved reserves(2)			
Oil equivalent (MMBOE)	15.9	14.5	9.1
% Oil	81%	80%	70%
% Proved producing	72%	67%	74%
PV-10 (millions)	$ 392.1	$ 200.3	$ 148.1
Proforma standardized measure (millions)(3)	$ 255.0	$ 132.1	$ 108.2

(1) The December 31, 2005, 2006 and 2007 information excludes the impact of our financial derivative activities.

(2) The estimates of reserves in the table above conform to the guidelines of the SEC. Estimated recoverable proved reserves have been determined without regard to any economic impact that may result from our financial derivative activities. These calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry. The estimated present value of proved reserves does not give effect to indirect expenses such as debt service and future income tax expense, asset retirement obligations or to depletion, depreciation and amortization. The reserve information shown is estimated. The accuracy of any reserve estimate is a function of the quality of available geological, geophysical, engineering and economic data, the precision of the engineering and geological interpretation and judgment. The estimates of reserves, future cash flows and present value are based on various assumptions, and are inherently imprecise. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates. Also, the use of a 10% discount factor for reporting purposes may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject.

(3) Because each of the Predecessor Companies was a flow-through entity for state and federal tax purposes, our historical standardized measure does not deduct state or federal taxes. This differs from our pro forma standardized measure, which deducts state and federal taxes.

Non-GAAP Financial Measures

We include in this report our calculations of EBITDAX and PV-10, which are non-GAAP financial measures. Below, we provide reconciliations of these non-GAAP financial measures to their most directly comparable financial measure as calculated and presented in accordance with GAAP.

EBITDAX

"EBITDAX" means, for any period, the sum of net income for such period plus the following expenses, charges or income to the extent deducted from or added to net income in such period: interest, income taxes, depreciation, depletion, amortization, unrealized losses from financial derivatives, exploration expenses and other similar non-cash charges, minus all non-cash income, including but not limited to, income from unrealized financial derivatives, added to net income. EBITDAX, as defined above, is used as a financial measure by our management team and by other users of our financial statements, such as our commercial bank lenders, to analyze such things as:

- Our operating performance and return on capital in comparison to those of other companies in our industry, without regard to financial or capital structure;
- The financial performance of our assets and valuation of the entity without regard to financing methods, capital structure or historical cost basis;
- Our ability to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our stockholders; and
- The viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

EBITDAX is not a calculation based on GAAP financial measures and should not be considered as an alternative to net income (loss) in measuring our performance, nor used as an exclusive measure of cash flow, because it does not consider the impact of working capital growth, capital expenditures, debt principal reductions, and other sources and uses of cash, which are disclosed in our statements of cash flows.

We have reported EBITDAX because it is a financial measure used by our existing commercial lenders and we believe this measure is commonly reported and widely used by investors as an indicator of a company's operating performance and ability to incur and service debt. You should carefully consider the specific items included in our computations of EBITDAX. While we have disclosed our EBITDAX to permit a more complete comparative analysis of our operating performance and debt servicing ability relative to other companies, you are cautioned that EBITDAX as reported by us may not be comparable in all instances to EBITDAX as reported by other companies. EBITDAX amounts may not be fully available for management's discretionary use, due to requirements to conserve funds for capital expenditures, debt service and other commitments.

We believe EBITDAX assists our lenders and investors in comparing a company's performance on a consistent basis without regard to certain expenses, which can vary significantly depending upon accounting methods. Because we may borrow money to finance our operations, interest expense is a necessary element of our costs and our ability to generate cash available for distribution. Because we use capital assets, depreciation and amortization are also necessary elements of our costs. Additionally, we are required to pay federal and state taxes, which are necessary elements of our costs. Therefore, any measures that exclude these elements have material limitations.

To compensate for these limitations, we believe it is important to consider both net income determined under GAAP and EBITDAX to evaluate our performance.

The following table presents a reconciliation of our net income to our EBITDAX for each of the periods presented ($ in thousands):

	Year Ended December 31,				
	2007	**2006**	**2005**	**2004**	**2003**
Net Income (Loss)	$(16,211)	$ 3,814	$(4,945)	$ 370	$ 628
Add Back Depletion, Depreciation, Amortization and Accretion	19,622	11,223	3,320	2,039	1,015
Add Back Non-Cash Compensation Expense	211	—	—	—	—
Add Back Interest Expense	5,646	6,110	1,697	867	171
Add Back Exploration & Impairment Expenses	2,948	—	107	3,024	—
Less Interest Income	(15)	(94)	(444)	(19)	(42)
Add Back Unrealized Losses (Gains) from Financial Derivatives	26,250	(5,043)	5,541	1,396	—
Add Back Minority Interest Share of Net Income (Loss)	(6,152)	2,133	2,304	(2,062)	(968)
Add Back (Less) Income Tax Expense (Benefit)	(7,017)	—	—	—	—
EBITDAX Before Minority Interests	$ 25,282	$18,143	$ 7,580	$ 5,615	$ 804

PV-10

The following table shows our reconciliation of our PV-10 to our pro forma standardized measure of discounted future net cash flows (the most directly comparable measure calculated and presented in accordance with GAAP). PV-10 represents our estimate of the present value, discounted at 10% per annum, of estimated future cash flows before income tax of our estimated proved reserves. Our estimated future cash flows as of December 31, 2005, 2006 and 2007 were determined by using reserve quantities of proved reserves and the periods in which they are expected to be developed and produced based on economic conditions prevailing on that date. The estimated future production is priced at December 31, 2005, 2006 and 2007, without escalation, using \$57.75, \$57.75 and \$92.50 per Bbl of oil, respectively, and \$10.08, \$5.635 and \$6.795 per MMBtu of natural gas, respectively, as adjusted by lease for transportation fees and regional price differentials. Management believes that PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our company. PV-10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP.

	2007	2006	2005
Reconciliation of PV-10 to Pro forma standardized measure (millions)			
Pro forma standardized measure of discounted future net cash flows	$255.0	$132.1	$108.2
Add: Present value of future income tax discounted at 10%	130.7	62.9	37.5
Add: Present value of future asset retirement obligations discounted at 10%	6.4	5.3	2.4
PV-10	$392.1	$200.3	$148.1

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

The following discussion and analysis should be read in conjunction with the "Selected Historical Financial Data" and the consolidated and combined financial statements and related notes included elsewhere in this report. This discussion contains forward-looking statements reflecting our current expectations and estimates and assumptions concerning events and financial trends that may affect our future operating results or financial position. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors, including those discussed in the sections entitled "Cautionary Note Regarding Forward-Looking Statements" and "Risk Factors" appearing elsewhere in this report.

Overview of Our Business

We are an independent oil and gas company operating in the Illinois Basin, Appalachian Basin and the Southwestern Region of the United States. We pursue a balanced growth strategy of exploiting our sizeable inventory of lower risk developmental drilling locations, pursuing our higher potential exploration drilling prospects and actively executing our acquisition strategy.

We are headquartered in State College, Pennsylvania, and have regional offices in Canonsburg (Pittsburgh), Pennsylvania, Midland, Texas and Bridgeport, Illinois.

Our financial results depend upon many factors, particularly the price of oil and gas. Commodity prices are affected by changes in market demand, which is impacted by overall economic activity, weather, refinery or pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future oil and gas prices, and therefore, we cannot determine what effect increases or decreases will have on our capital program, production volumes and future revenues. In addition to production volumes and commodity prices, finding and developing sufficient amounts of oil and gas reserves at economical costs are critical to our long-term success.

Source of Our Revenues

We generate our revenue primarily from the sale of crude oil to refining companies and natural gas to local distribution and pipeline companies. Our operating revenue before the effects of financial derivatives from these operations, and their relative percentages of our total revenue, consisted of the following ($ in thousands):

	2007	% of Total	2006	% of Total	2005	% of Total
Revenue from Oil Sales	$55,542	86.8%	$35,790	81.2%	$20,355	68.3%
Revenue from Natural Gas Sales	7,983	12.5%	7,806	17.7%	9,163	30.8%
Other	452	0.7%	470	1.1%	270	0.9%
Total	$63,977	100.0%	$44,066	100.0%	$29,788	100.0%

We have identified the impact of generally higher commodity prices in the last several years as compared with prior periods as an important trend that we expect to affect our business in the future. If commodity prices continue at the present relatively high levels or increase, we would expect this trend to result not only in increased revenue, but also in an increasingly competitive environment for quality drilling prospects, qualified geological and technical personnel and oil field services, including rig availability. Increasing competition in these areas, which we expect to increase so long as commodity prices remain relatively high, will likely result in higher costs in these areas, and could result in unavailability of drilling rigs, thus affecting the profitability of our future operations. We may not be able to compete successfully in the future with larger competitors in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital. In the event of a declining commodity price environment, our revenues would decrease and we would anticipate that the cost of materials and services would decrease as well, although at a slower rate. Decreasing oil or natural gas prices may also make some of our prospects uneconomic to drill.

Principal Components of Our Cost Structure

Our operating and other expenses consist of the following:

- *Production and Lease Operating Expenses.* These are day-to-day costs incurred to bring hydrocarbons out of the ground and to the market together with the daily costs incurred to maintain our producing properties. Such costs also include workovers, repairs to our oil and gas properties not covered by insurance, and various production taxes that are paid based upon rates set by federal, state, and local taxing authorities.
- *Exploration Expense.* Geological and geophysical costs, seismic costs, delay rentals and the costs of unsuccessful exploratory wells or dry holes.
- *General and Administrative Expense.* Overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, audit and other professional fees and legal compliance are included in general and administrative expense. General and administrative expense includes stock-based compensation expense (non-cash) associated with the adoption of SFAS No. 123(R) as part of employee compensation.
- *Interest.* We typically finance a portion of our working capital requirements and acquisitions with borrowings under our senior credit facility. As a result, we incur substantial interest expense that is affected by both fluctuations in interest rates and our financing decisions. We may continue to incur significant interest expense as we continue to grow.
- *Depreciation, Depletion, Amortization and Accretion.* The systematic expensing of the capital costs incurred to acquire, explore and develop natural gas and oil. As a successful efforts company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and apportion these costs to each unit of production through depreciation, depletion and amortization expense. This also includes the systematic, monthly accretion of the future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities.
- *Income Taxes.* We are subject to state and federal income taxes but are currently not in a tax paying position for regular federal income taxes, primarily due to the current deductibility of intangible drilling costs ("IDC"). We do pay some state income taxes where our IDC deductions do not exceed our taxable income or where state income taxes are determined on another basis. Currently, all of our federal taxes are deferred; however, at some point, we believe we will use all of our net operating loss carryforwards and we believe we will recognize current income tax expense and continue to recognize current tax expense as long as we are generating taxable income.

How We Evaluate Our Operations

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include EBITDAX, lease operating expenses per BOE, growth in our proved reserve base and general and administrative expenses as a percentage of revenue. The following table presents these metrics for each of the three years ended December 31, 2007, 2006 and 2005.

	Performance Measurements		
	Years Ended December 31,		
	2007	2006	2005
EBITDAX ($ in Thousands)	$25,282	$18,143	$7,580
Production Cost per BOE	$ 24.28	$ 19.72	$20.70
Total Proved Reserves (MMBOE)	15.9	14.5	9.1
G&A as a Percentage of Operating Revenue	14.9%	15.7%	17.3%

EBITDAX

"EBITDAX" means, for any period, the sum of net income for such period plus the following expenses, charges or income to the extent deducted from or added to net income in such period: interest, income taxes, depreciation, depletion, amortization, unrealized losses from financial derivatives, exploration expenses and other similar non-cash charges, minus all non-cash income, including but not limited to, income from unrealized financial derivatives, added to net income. EBITDAX, as defined above, is used as a financial measure by our management team and by other users of our financial statements, such as our commercial bank lenders, to analyze such things as:

- Our operating performance and return on capital in comparison to those of other companies in our industry, without regard to financial or capital structure;
- The financial performance of our assets and valuation of the entity, without regard to financing methods, capital structure or historical cost basis;
- Our ability to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our stockholders; and
- The viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Production Cost per BOE

Production costs are comprised of those expenses which are directly attributable to our producing oil and gas leases, including state and county production taxes, production related insurance, the cost of materials, maintenance, electricity, chemicals, fuel and the wages of our field personnel. Our production costs per BOE are higher than those of many of our peers primarily because of the nature of our oil properties, many of which are mature waterflood properties. As we continue to develop our non-proved properties, we believe this metric will decrease on a per unit basis. Our production costs per BOE produced in 2007 was $24.28 as compared to $19.72 in 2006 and $20.69 in 2005.

Growth in our Proved Reserve Base

We measure our ability to grow our proved reserves over the amount of our total annual production. As we produce oil and gas attributable to our proved reserves, our proved reserves decrease each year by that amount of production. We attempt to replace these produced proved reserves each year through the addition of new proved reserves through our drilling and other property improvement projects and through acquisitions. Our proved reserves have risen significantly since 2005, from 9.1 MMBOE at year end 2005 to 14.5 MMBOE at year end 2006 to 15.9 MMBOE at year end 2007. Our reserve replacement ratio for year end 2005 was approximately 833% based on an increase in total proven reserves of 5 MMBOE, total production for the year of 577 MBOE, proven reserve divestitures of 400 MBOE, purchases of reserves of 4.4 MMBOE, extensions discoveries and other additions of 11 MBOE, and revisions of previous estimates of 1.5 MMBOE. Our reserve replacement ratio for year end 2006 was approximately 675% based on an increase in total proven reserves of 5.4 MMBOE, total production for the year of 770 MBOE, purchases of reserves of 6.7 MMBOE, extensions discoveries and other additions of 198 MBOE, and revisions of previous estimates of negative 707 MBOE. Our reserve replacement ratio for year end 2007 was approximately 139% based on an increase in total proven reserves of 1.4 MMBOE, total production for the year of 1.0 MMBOE, purchases of reserves of 84 MBOE, extensions discoveries and other additions of 342 MBOE, and revisions of previous estimates of 2.0 MMBOE.

General and Administrative Expenses as a Percentage of Oil and Gas Revenue

Our general and administrative expenses include fees for well operating services, marketing, non-field level employee compensation and related benefits, office and lease expenses, insurance costs and professional fees, as well as other costs and expenses not directly related to field operations. Our management continually evaluates

the level of our general and administrative expenses in relation to our revenue because these expenses have a direct impact on our profitability. Our general and administrative expenses as a percentage of oil and gas revenue decreased in 2007 to 14.9% from 15.7% in 2006 and from 17.3% in 2005. Although we anticipate our general and administrative expenses will increase over the next two years as a result of additional administrative expenses associated with our anticipated growth, our goal is to reduce our general and administrative expenses as a percentage of our revenue to below 10% through an increase in our production while endeavoring to limit growth in our overhead expenses.

Results of Operations

General Overview

Operating revenue increased 45.8% for 2007 over 2006. This increase is primarily due to higher production with higher average sales prices per BOE, partially offset by increased realized losses on derivative activity. For 2007, production increased 30.5% from 2006 to 1,008,190 BOE compared to 772,386 BOE in 2006 due to the continued success of our drilling programs and our acquisitions. Realized losses on derivative activities increased by 39.7% to $6.2 million for 2007 as compared to $4.4 million for 2006.

Operating expenses increased $23.0 million in 2007, or 70.3%, as compared to 2006. Operating expenses are primarily composed of production expenses, general and administrative expenses, exploration expenses, and depreciation, depletion, amortization, and accretion expenses. These increases were due, in part, to acquisitions consummated in the final six months of 2006 within the Illinois basin whereby we acquired all of the oil producing assets owned by Tsar Energy II, L.L.C. and certain oil producing assets owned by Team Energy, L.L.C. and its affiliates. The increase is also partially attributed to approximately $2.1 million of increased depreciation, depletion and amortization expenses realized over the five-month period ended December 31, 2007 resulting from a step-up in book basis of assets caused by the acquisition of all minority interests from the Predecessor Companies.

Comparison of the Year Ended December 31, 2007 to the Year Ended December 31, 2006

Oil and gas revenue for the years ended December 31, 2007 and 2006 ($ in thousands except price per BOE) is summarized in the following table:

	December 31,			
	2007	2006	(Change)	%
Oil and Gas Revenues:				
Oil sales revenue	$ 55,542	$ 35,790	$ 19,752	55.2
Oil derivatives realized	(6,828)	(5,377)	(1,451)	(27.0)
Total oil revenue	$ 48,714	$ 30,413	$ 18,301	60.2
Gas sales revenue	$ 7,983	$ 7,806	$ 177	2.3
Gas derivatives realized	630	941	(311)	(33.0)
Total gas revenue	$ 8,613	$ 8,747	$ (134)	(1.5)
Consolidated sales	$ 63,525	$ 43,596	$ 19,929	45.7
Consolidated derivatives realized	(6,198)	(4,436)	(1,762)	(39.7)
Total oil & gas revenue	$ 57,327	$ 39,160	$ 18,167	46.4
Total BOE Production	1,008,190	772,386	235,827	30.5
Average Realized Price per BOE	$ 56.86	$ 50.70	$ 6.16	12.2

Average realized price received for oil and gas during 2007 was $56.86 per BOE, an increase of 12.2%, or $6.16 per BOE, from the prior year. The average realized price for oil in 2007 increased 15.5% or $8.01 per barrel, whereas the average realized price for natural gas decreased 5.8%, or $0.46 per Mcf, from 2006. Our derivative activities effectively decreased net realized prices by $6.15 per BOE in 2007 and $5.74 per BOE in 2006.

Production volumes increased 30.5% from 2006 primarily due to acquisitions in the Illinois Basin and continued success with our oil and gas well drilling activities. Our production for 2007 averaged approximately 2,762 BOE per day of which 76.4% was attributable to the Illinois basin, 13.0% to the Appalachian basin, and 10.6% to activities in the Southwestern region.

Other operating revenue for 2007 of approximately $452,000 decreased $18,000, or 3.8%, from 2006. We generate other operating revenue from various activities such as revenue from the transportation of natural gas and disposal of salt water from non-related parties through a salt water disposal facility we own and operate for our own oil and gas production activities in the Southwestern region.

Production and lease operating expenses increased approximately $9.2 million, or 60.7%, in 2007 from 2006. These expenses typically increase as we add new wells and make certain improvements to existing wells in production. These increases were principally due to acquisitions consummated in the final six months of 2006 within the Illinois basin from Tsar Energy II, L.L.C. and Team Energy, L.L.C. and its affiliates.

General and administrative expenses of approximately $8.6 million for 2007 increased approximately $2.4 million, or 38.2%, from 2006. This increase was primarily as a result of oil and gas property acquisitions in the Illinois basin during the final six months of 2006 which resulted in reduced overhead income on wells that we operated for Tsar Energy II, L.L.C. This overhead income had offset general and administrative expenses. In October of 2006, we acquired all of the interests of Tsar Energy II, L.L.C. in these wells at which time we ceased to recognize the overhead income associated with these wells. Additionally, with the completion of our initial public offering in July 2007, we have recognized increases to salary and benefit expenses associated with increased staffing levels.

DD&A expenses of approximately $19.6 million for 2007 increased approximately $8.4 million, or 74.8%, from 2006. This increase was partially due to an increase in production volumes resulting from the Tsar Energy II, L.L.C. and Team Energy, L.L.C. acquisitions in the Illinois basin. The increase is also partially attributed to approximately $2.1 million of increased depletion and amortization expenses realized over the five month period ending December 31, 2007 resulting from a step-up in book basis of assets caused by the acquisition of minority interests from the Predecessor Companies.

Interest expense, net of interest income for 2007 was approximately $5.6 million as compared to $6.0 million for 2006. The decrease of $385,000 is primarily due to the decrease in the average balance on our long-term debt, lines of credit, and other loans and notes payable which have been significantly reduced with the proceeds of our initial public offering, which closed July 30, 2007.

Gain on sale of oil and gas properties for 2007 was approximately $185,000 as compared to $91,000 for 2006. We, from time to time, sell or otherwise dispose of certain fixed assets and wells that are no longer effectively used by us and a gain or loss may be recognized when such an asset is sold.

Unrealized loss on oil and gas derivatives for 2007 was approximately $26.3 million as compared to a gain of $5.0 million for 2006. These changes are attributed to the volatility of oil and gas commodity prices in the marketplace along with changes in our portfolio of outstanding collars and swap derivatives. Unrealized losses from derivative activities generally reflect higher oil and gas prices in the marketplace than were in effect at the time we entered into a derivative contract while unrealized gains would suggest the opposite. Our derivative program is designed to provide us with a greater reliability of future cash flows at expected levels of oil and gas production volumes given the highly volatile oil and gas commodities market.

Other income (expense) increased by 230% to approximately $171,000 of income for 2007 from approximately $132,000 of expense for 2006. The change year over year is primarily due to the recognition of gains on the sale of scrap inventory.

Net loss before minority interests for 2007 was approximately $29.4 million, a decrease of approximately $35.3 million from net income of approximately $5.9 million for 2006 as a result of the factors discussed above.

Comparison of the Year Ended December 31, 2006 to the Year Ended December 31, 2005

Oil and gas revenue for the years ended December 31, 2006 and 2005 ($ in thousands except price per BOE) is summarized in the following table:

	December 31,			
	2006	2005	(Change)	%
Oil and Gas Revenues:				
Oil sales revenue	$ 35,790	$ 20,355	$ 15,435	75.8
Oil derivatives realized	(5,377)	(3,285)	(2,092)	(63.7)
Total oil revenue	$ 30,413	$ 17,070	$ 13,343	78.2
Gas sales revenue	$ 7,806	$ 9,163	$ (1,357)	(14.8)
Gas derivatives realized	941	(4,645)	5,586	120.3
Total gas revenue	$ 8,747	$ 4,518	$ 4,229	93.6
Consolidated sales	$ 43,596	$ 29,518	$ 14,078	47.7
Consolidated derivatives realized	(4,436)	(7,930)	3,494	44.1
Total oil & gas revenue	$ 39,160	$ 21,588	$ 17,572	81.4
Total BOE Production	772,386	566,411	205,952	36.4
Average Realized Price per BOE	$ 50.70	$ 38.11	$ 12.59	33.0

Average realized price received for oil and gas during 2006 was $50.70 per BOE, an increase of 33.0%, or $12.59 per BOE, from the prior year. The average realized price for oil in 2006 increased 14.9% or $6.73 per barrel, whereas the average realized price for natural gas increased 96.2%, or $3.87 per Mcf, from 2005. Our derivative activities effectively decreased net realized prices by $5.74 per BOE in 2006 and $14.00 per BOE in 2005.

Production volumes increased 36.4% for the year ended December 31, 2006, as compared to the same period in 2005, primarily due to acquisitions in the Illinois Basin and continued success with our oil and gas well drilling activities. Our production for the year averaged approximately 2,116 BOE per day of which 70.7% was attributable to the Illinois basin, 14.0% to the Appalachian basin, and 15.3% to activities in the Southwestern region.

Other operating revenue for the year ended December 31, 2006 increased $200,000 to $470,000 from $270,000 for the same period in 2005. We generate other operating revenue from various activities such as revenue from the transportation of natural gas and disposal of salt water from non-related parties through a salt water disposal facility we own and operate for our own oil and gas production activities in the Southwestern region.

Production and lease operating increased approximately $3.5 million, or 30.0%, in 2006 from 2005. These expenses typically increase as we add new wells and make certain improvements to existing wells in production. These increases were principally due to acquisitions consummated in the final six months of 2006 within the Illinois basin from Tsar Energy II, L.L.C. and Team Energy, L.L.C. and its affiliates.

General and administrative expenses increased $2.4 million from 2005 to 2006. The increase in G&A expense was principally due to increases in legal expenses associated with a lawsuit which was settled in October 2006, increased legal expenses associated with our U.S. EPA enforcement matter and the putative class action lawsuit, and increases in the number of employees we had and other expenses associated with our growth. In

addition, the acquisition of non-operated working interests associated with the TSAR Energy II acquisition, which we operated before the acquisition, reduced the amount of overhead fees we received from third parties which were recorded as a deduction of our G&A expense. This reduction in overhead fees accounted for approximately 20% of the $2.4 million increase.

Depreciation, depletion, amortization, and accretion (“DD&A”) expenses for the year ended December 31, 2006 increased approximately $7.9 million, or 238%, from $3.3 million for the same period in 2005. This increase was partially due to an increase in production volumes and depletable assets resulting from the Tsar Energy II, L.L.C. and Team Energy, L.L.C. acquisitions in the Illinois basin during 2006.

Interest expense, net of interest income for the year ended December 31, 2006 was approximately $6.0 million as compared to $1.3 million for the same period in 2005. The increase of $4.8 million resulted from increased borrowings associated with our 2006 acquisitions.

Gain on sale of oil and gas properties for the year ended December 31, 2006 was approximately $91,000 as compared to $1.0 million for the same period in 2005. We, from time to time, sell or otherwise dispose of certain fixed assets and wells that are no longer effectively used by us and a gain or loss may be recognized when such an asset is sold.

Unrealized loss on oil and gas derivatives includes a gain of approximately $5.0 million for the year ended December 31, 2006 as compared to a loss of $5.5 million for the same period in 2005. These changes are attributed to the volatility of oil and gas commodity prices in the marketplace along with changes in our portfolio of outstanding collars and swap derivatives. Unrealized losses from derivative activities generally reflect higher oil and gas prices in the marketplace than were in effect at the time we entered into a derivative contract while unrealized gains would suggest the opposite. Our derivative program is designed to provide us with a greater reliability of future cash flows at expected levels of oil and gas production volumes given the highly volatile oil and gas commodities market.

Other income (expense) decreased by $348,000 to an expense of $132,000 for the year ended December 31, 2006 as compared to income of $216,000 for the same period in 2006. The change was due to expenses related to property damage at one of our facilities in 2006.

Net income (loss) before minority interests increased from a loss of $2.6 million in 2005 to income of $5.9 million in 2006. Minority Interest Share of Income decreased from $2.3 million in 2005 to $2.1 million in 2006 as a result of the factors described above.

Capital Resources and Liquidity

Our primary financial resource is our base of oil and gas reserves. We pledge our producing oil and gas properties to a group of banks to secure our senior credit facility. The banks establish a borrowing base by making an estimate of the collateral value of our oil and gas properties. We borrow funds on the senior credit facility as needed to supplement our operating cash flow and as a financing source for our capital expenditure program. Our ability to fund our capital expenditure program is dependent upon the level of product prices and the success of our exploration program in replacing our existing oil and gas reserves. If product prices decrease, our operating cash flow may decrease and the banks may require additional collateral or reduce our borrowing base, thus reducing funds available to fund our capital expenditure program. The effects of product prices on cash flow can be mitigated through the use of commodity derivatives. If we are unable to replace our oil and gas reserves through our acquisitions, development or exploration programs, we may also suffer a reduction in our operating cash flow and access to funds under the senior credit facilities. Under extreme circumstances, product price reductions or exploration drilling failures could allow the banks to seek to foreclose on our oil and gas properties, thereby threatening our financial viability.

Our cash flow from operations is driven by commodity prices and production volumes. Prices for oil and gas are driven by, among other things, seasonal influences of weather, national and international economic and political environments and, increasingly, from heightened demand for hydrocarbons from emerging nations, particularly China and India. Our working capital is significantly influenced by changes in commodity prices, and significant declines in prices could decrease our exploration and development expenditures. Cash flows from operations have been primarily used to fund exploration and development of our oil and gas interests.

Financial Condition and Cash Flows for the Years Ended December 31, 2007, 2006 and 2005

The following table summarizes our sources and uses of funds for the periods noted:

	For The Years Ended December 31, ($ in Thousands)		
	2007	2006	2005
Cash flows provided by operating activities	$ 17,555	$ 12,920	$ 9,527
Cash flows used in investing activities	(40,102)	(94,446)	(19,404)
Cash flows provided by financing activities	23,032	79,438	9,772
Net increase (decrease) in cash and cash equivalents	$ 485	$ (2,088)	$ (105)

Net cash provided by operating activities increased by approximately $4.6 million in 2007 when compared to 2006, to $17.6 million. In 2007, cash flows increased primarily due to increases in production, which were a result of acquisitions in the Illinois Basin during the final six months of 2006 and continued success with our oil and gas well drilling activities, and higher realized prices. These increases in cash were partially offset by increases in operating expenses, which were also primarily due to the acquisitions in the Illinois Basin that took place in the second half of 2006.

Net cash used in investing activities decreased by approximately $54.3 million in 2007 when compared to 2006, to $40.1 million. In 2007, cash used decreased primarily as a result of the acquisitions in the Illinois Basin during 2006. This decrease was partially offset by increased expenditures in 2007 for the development of oil and gas properties as part of the 2007 drilling and recompletion program and an increase in the proceeds received on the sale of oil and gas properties, prospects, and other assets.

Net cash provided by financing activities decreased by approximately $56.4 million in 2007 when compared to 2006, to 23.0 million. In 2007, cash flows provided by financing decreased primarily due to the combination of increased borrowings in 2006 to fund the acquisitions that took place in the Illinois Basin and the large repayment of debt in 2007 with the proceeds of our initial public offering. Also contributing to the decrease in cash flows during 2007 were increased repayments of participation liability and a decrease in the net capital contributions from the Partners of the Predecessor Companies. These decreases in cash flow were partially offset by a decrease in payments to related parties.

Capital Requirements

Our primary needs for cash are for exploration, development and acquisition of oil and gas properties and repayment of principal and interest on outstanding debt. During 2007, $40.4 million of capital was expended on drilling projects, facilities and related equipment and acquisitions to purchase additional interests in producing properties and unproved acreage. The capital program was funded by net cash flow from operations and proceeds from borrowings. The 2008 capital budget of $138.7 million is expected to be funded primarily by cash flow from operations and proceeds from borrowings. To the extent capital requirements exceed internal cash flow and proceeds from asset sales, debt or equity may be issued to fund these requirements. We currently believe we have sufficient liquidity and cash flow to meet our obligations for the next twelve months; however, a drop in oil and gas prices or a reduction in production or reserves could adversely affect our ability to fund capital expenditures

and meet our financial obligations. Also, our obligations may change due to acquisitions, divestitures and continued growth. We may issue additional shares of stock, subordinated notes or other debt securities to fund capital expenditures, acquisitions, extend maturities or to repay debt.

Effects of Inflation and Changes in Price

Our results of operations and cash flows are affected by changing oil and natural gas prices. If the price of oil and natural gas increases (decreases), there could be a corresponding increase (decrease) in the operating cost that we are required to bear for operations, as well as an increase (decrease) in revenues. Inflation has had a minimal effect on us.

Critical Accounting Policies and Recently Adopted Accounting Pronouncements

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the periods reported. Actual results could differ from these estimates.

Significant estimates include volumes of oil and natural gas reserves used in calculating depletion of proved oil and natural gas properties, future cash flows, asset retirement obligations, impairment (when applicable) of undeveloped properties, the collectability of outstanding accounts receivable, fair values of financial derivative instruments, contingencies, and the results of current and future litigation. Oil and natural gas estimates, which are the basis for unit-of-production depletion, have numerous inherent uncertainties. The accuracy of any reserve estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Subsequent drilling results, testing, and production may justify revision of such estimates. 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. These prices have been volatile in the past and can be expected to be volatile in the future.

The significant estimates are based on current assumptions that may be materially effected by changes to future economic conditions such as the market prices received for sales of volumes of oil and natural gas, interest rates, and our ability to generate future income. Future changes in these assumptions may materially affect these significant estimates in the near term.

Natural Gas and Oil Reserve Quantities

Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. For the year ended December 31, 2005, our independent engineering firm, Netherland, Sewell, and Associates, Inc., prepared a reserve and economic evaluation of each of the Predecessor Companies' proved oil and gas reserves which has been combined by us to determine our total proved oil and gas reserves for the period. For the years ended December 31, 2006 and 2007, Netherland Sewell and Associates, Inc. prepared a consolidated reserve and economic evaluation of our proved oil and gas reserves.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. We prepare our reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. Our independent engineering firm adheres to the same guidelines when preparing their reserve reports. The accuracy of our reserve estimates is a function of many factors, including the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates. Any of the assumptions inherent in

these factors could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of natural gas and oil eventually recovered. The independent reserve engineer estimates reserves annually on December 31. This annual estimate results in a new DD&A rate which we use for the preceding fourth quarter after adjusting for fourth quarter production.

Derivative Instruments

We use put and call options (collars) and fixed rate swap contracts to manage price risks in connection with the sale of oil and natural gas. We also use interest-rate swap agreements to manage interest-rate risks associated with our variable-rate credit facility. We account for these collar and swap contracts using Statement of Financial Accounting Standards No. 133, "*Accounting for Derivative Instruments and Hedging Activities,*" ("SFAS No. 133").

We have established the fair value of all derivative instruments using estimates determined by our counterparties. These values are based upon, among other things, future prices, volatility, time to maturity, and credit risk. The values we report in our consolidated financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

SFAS No. 133 establishes accounting and reporting standards requiring derivative instruments (including certain derivative instruments embedded in other contracts or agreements) be recorded at fair value and included in the Consolidated Balance Sheets as assets or liabilities. The accounting for changes in fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designed as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any changes in fair value resulting from ineffectiveness, as defined by SFAS No. 133, is recognized immediately in earnings.

For derivative instruments designated as fair value hedges (in accordance with SFAS No. 133), changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings. Derivative effectiveness is measured annually based on the relative changes in fair value between the derivative contract and the hedged item over time. For derivatives on oil and natural gas production activity, our evaluations are not documented, and as a result, we record changes on the derivative valuations through earnings.

Oil and Natural Gas Property, Depreciation and Depletion

We account for natural gas and oil exploration and production activities under the successful efforts method of accounting. Proved developed natural gas and oil property acquisition costs are capitalized when incurred. Unproved properties with individually significant acquisition costs are assessed quarterly on a property-by-property basis, and any impairment in value is recognized. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved natural gas and oil properties. Natural gas and oil exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether they have discovered proved commercial reserves. If proved commercial reserves are not discovered, such drilling costs are expensed. Costs to develop proved reserves, including the costs of all development well and related equipment used in the production of natural gas and oil are capitalized.

Depletion, depreciation and amortization are calculated using the unit-of-production method on estimated proved developed producing oil and gas reserves at the lease or well level. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. We periodically review our estimated proved reserve estimates and makes changes as needed to depletion, depreciation and amortization expenses to account

for new wells drilled, acquisitions, divestitures and other events which may have caused significant changes in our estimated proved developed producing reserves. The costs of unproved properties are withheld from the depletion base until such time as they are either developed or abandoned. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion calculations. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Undeveloped leasehold cost is transferred to the associated producing properties. Individually significant non-producing properties are periodically assessed for impairment of value. Service properties, equipment and other assets are depreciated using the straight-line method over their estimated useful lives of 3 to 30 years.

We account for impairment under the provisions of SFAS No. 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets*." When circumstances indicate that an asset may be impaired, we compare expected undiscounted future cash flows at a producing field to the unamortized capitalized cost of the asset. If the future undiscounted cash flows, based on our estimate of future natural gas and oil prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate. At December 31, 2007 oil and gas properties valued at $642,000 were impaired and included in depreciation, depletion, and amortization on the consolidated and combined statement of operations for the year ended December 31, 2007. The impairment expense represents 100% of the carrying value of those assets associated with a coalmine methane project in West Virginia for which we can no longer identify a suitable market for the methane gas produced by the mine.

Expenditures for repairs and maintenance to sustain or increase production from the existing producing reservoir are charged to expense as incurred. Expenditures to recomplete a current well are capitalized pending determination that economic reserves have been added. If the recompletion is not successful, the expenditures are charged to expense.

Significant tangible equipment added or replaced that extends the useful or productive life of the property is capitalized. Expenditures to construct facilities or increase the productive capacity from existing reservoirs are capitalized.

Upon the sale or retirement of a proved natural gas or oil property, or an entire interest in unproved leaseholds, the cost and related accumulated depreciation, depletion, and amortization are removed from the property accounts and the resulting gain or loss is recognized. For sales of a partial interest in unproved leaseholds for cash or cash equivalents, sales proceeds are first applied as a reduction of the original cost of the entire interest in the property and any remaining proceeds are recognized as a gain.

Goodwill and Intangible Assets

In accordance with SFAS No. 142, "*Goodwill and Other Intangible Assets*" ("SFAS 142"), no amortization is recorded for goodwill or intangible assets deemed to have indefinite lives for acquisitions completed after June 30, 2001. SFAS No. 142 requires that goodwill and non-amortizable assets be assessed annually for impairment. At December 31, 2007, our intangible assets consist of $32.7 million of goodwill and $1.3 million of intangible assets comprised of sales agreements that are amortized over an estimated useful life of five years. For the years ended December 31, 2007, 2006, and 2005, we recorded amortization expense of $111,000, $0 and $0, respectively. Amortization expenses were recorded only for those periods following the Reorganization Transactions. We are in the early stages of gathering data and performing an analysis and evaluation of the assets and liabilities assumed as of the date of acquisition. We have preliminarily estimated the excess cost over the fair values of those assets and liabilities. To the extent that the estimates used in the preliminary purchase price allocation need to be adjusted, we will do so upon making that determination, but not later than one year from the date of acquisition.

Goodwill and identified intangible assets that have an indefinite useful life are subject to impairment testing, which we conduct annually, or on an interim basis if events or changes in circumstances between annual tests indicate the assets might be impaired. We perform our annual impairment test for goodwill and identified intangible assets that have an indefinite useful life as of December 31 of each year. The impairment test involves a comparison of the fair value of each tangible and intangible asset to its carrying value. If the fair value is less than the carrying value, a further test is required to measure the amount of impairment.

Future Abandonment Cost

We account for future abandonment costs using SFAS No. 143, *"Asset Retirement Obligations."* This statement applies to obligations associated with the retirement of tangible long-lived assets that result from the acquisition and development of the asset. SFAS No. 143 requires that the fair value of a liability for a retirement obligation be recognized in the period in which the liability is incurred. For natural gas and oil properties, this is the period in which the natural gas or oil well is acquired or drilled. The future abandonment cost is capitalized as part of the carrying amount of our natural gas and oil properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the natural gas or oil well is sold, at which time the liability is reversed.

Deferred Taxes

We are subject to income and other taxes in all areas in which we operate. When recording income tax expense, certain estimates are required because income tax returns are generally filed many months after the close of a calendar year, tax returns are subject to audit which can take years to complete and future events often impact the timing of when income tax expenses and benefits are recognized. We have deferred tax assets relating to tax operating loss carry forwards and other deductible differences. We routinely evaluate deferred tax assets to determine the likelihood of realization. A valuation allowance is recognized on deferred tax assets when we believe that certain of these assets are not likely to be realized.

We may be challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in our various income tax returns. Although we believe that we have adequately provided for all taxes, gains or losses could occur in the future due to changes in estimates or resolution of outstanding tax matters.

Contingent Liabilities

A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost or range of cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and contingent matters. In addition, we often must estimate the amount of such losses. In many cases, our judgment is based on the input of our legal advisors and on the interpretation of laws and regulations, which can be interpreted differently by regulators and/or the courts. We monitor known and potential legal, environmental and other contingent matters and make our best estimate of when to record losses for these matters based on available information. We have recognized an accrued liability of approximately $384,000 at December 31, 2007 for the estimated cost of pending litigation matters.

Accounting Standards Not Yet Adopted

In February 2007, the FASB issued SFAS No. 159, "*The Fair Value Option for Financial Assets and Financial Liabilities*." This statement permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measure at fair value. It requires that unrealized gains and losses on items for which the fair value option has been elected be recorded in net income. The statement also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. For us,

SFAS No. 159 will be effective January 1, 2008, and retrospective application is not permitted. Should we elect to apply the fair value option to any eligible items that exist at January 1, 2008, the effect of the first re-measurement to fair value would be reported as a cumulative effect adjustment to the opening balance of retained earnings. We will adopt SFAS No. 159 as of January 1, 2008 and do not expect the adoption will have a material impact on our financial statements.

In September 2006, the FASB issued SFAS No. 157, "*Fair Value Measurement*." This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements but may require some entities to change their measurement practices. For us, SFAS No. 157 will be effective January 1, 2008. We have not yet determined whether SFAS No. 157 will have a material impact on our financial condition, results of operations or cash flow. However, we believe we will be required to provide additional disclosures as part of future financial statements, beginning with the first quarter of 2008.

In December 2007, the FASB issued SFAS No. 141(R), "*Business Combinations.*" SFAS No. 141(R) replaces SFAS No. 141. The statement retains the purchase method of accounting for acquisitions, but requires a number of changes, including changes in the way assets and liabilities are recognized in the purchase accounting. It changes the recognition of assets acquired and liabilities assumed arising from contingencies, requires the capitalization of in-process research and development at fair value, and requires the expensing of acquisition-related costs as incurred. The statement will apply prospectively to business combinations occurring in our fiscal year beginning January 1, 2009. We are currently evaluating provisions of this statement.

In December 2007, the FASB issued SFAS No. 160, *"Noncontrolling Interests in Consolidated Financial Statements" ("SFAS 160")*, which provides direction on reporting minority (noncontrolling) interests in the consolidated financial statements. The standards set forth in SFAS No. 160 include clearly identifying and labeling noncontrolling interests in the consolidated statement of equity, separate from the parent's equity; clearly identifying consolidated net income of the parent and the noncontrolling interests on the consolidated statement of income; consistently accounting for changes in the parent ownership interest when the parent preserves its controlling interest; any retained noncontrolling equity investment of a deconsolidated subsidiary and any resulting gain or loss will be measured using fair value and; disclosures must provide a level of detail that clearly identifies and separates the interests of the parent and the interest of the noncontrolling owners. SFAS 160 is effective for fiscal years beginning on or after December 15, 2008, and interim periods within those fiscal years. We are currently evaluating the effect that the implementation of SFAS 160 will have on our results of operations and financial condition, but do not expect it will have a material impact.

Volatility of Oil and Natural Gas Prices

Our revenues, future rate of growth, results of operations, financial condition 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.

We account for our natural gas and oil exploration and production activities under the successful efforts method of accounting. See Note 2 to our consolidated and combined financial statements—"*Summary of Significant Accounting Policies.*"

To mitigate some of our commodity price risk, we engage periodically in certain other limited derivative activities including price swaps and costless collars to establish some price floor protection.

For the twelve month periods ended December 31, 2007 and 2006, the net realized loss on oil and natural gas derivatives was approximately $6.2 million and $4.4 million, respectively. The losses are reported as net realized loss on derivatives in the Consolidated and Combined Statements of Operations.

For the twelve month period ended December 31, 2007, the net unrealized loss on oil and natural gas derivatives was approximately $26.3 million as compared to a net unrealized gain of approximately $5.0 million on oil and natural gas derivatives for 2006. The net unrealized gains and losses are reported as net unrealized gains (losses) on derivatives in the Consolidated and Combined Statements of Operations.

While the use of derivative arrangements limits the downside risk of adverse price movements, it may also limit our ability to benefit from increases in the prices of natural gas and oil. We enter into the majority of our derivatives transactions with two counterparties and have a netting agreement in place with each of these counterparties. We do not obtain collateral to support the agreements but monitor the financial viability of counterparties and believe our credit risk is minimal on these transactions. Under these arrangements, payments are received or made based on the differential between a fixed and a variable commodity price. These agreements are settled in cash at expiration or exchanged for physical delivery contracts. In the event of nonperformance, we would be exposed again to price risk. We have additional risk of financial loss because the price received for the product at the actual physical delivery point may differ from the prevailing price at the delivery point required for settlement of the derivative transaction. Moreover, our derivatives arrangements generally do not apply to all of our production and thus provide only partial price protection against declines in commodity prices. We expect that the amount of our derivatives will vary from time to time.

For a summary of our current oil and natural gas derivative positions at December 31, 2007 refer to Note 9 to our consolidated and combined financial statements, *"Fair Value of Financial Instruments and Derivative"*.

Contractual Obligations

In addition to our capital expenditure program, we are committed to making cash payments in the future on two types of contracts: note agreements and operating leases. As of December 31, 2007, we do not have any capital leases nor have we entered into any material long-term contracts for equipment. As of December 31, 2007, we do not have any off-balance sheet debt or other such unrecorded obligations and we have not guaranteed the debt of any other party. The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2007. In addition to the contractual obligations listed on the table below, our balance sheet at December 31, 2007 reflects accrued interest payable on our bank debt of $114,566 which is payable in January 2008.

The following summarizes our contractual financial obligations at December 31, 2007 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities.

	Payment due by period				
	2008	2009 and 2010	2011 and 2012	Thereafter	Total
	(in thousands)				
Bank debt	$ 29	$ 21	$ —	$27,186	$27,236
Operating leases	354	772	709	436	2,271
Drilling contracts	1,700	3,400	3,400	1,700	10,200
Derivative obligations(a)	10,873	18,842	—	—	29,715
Asset retirement obligation liability	—	—	—	6,396	6,396
Total contractual obligations	$12,956	$23,035	$4,109	$35,718	$75,818

(a) Derivative obligations represent net open derivative contracts valued as of December 31, 2007.

Interest Rates

At December 31, 2007, we had $27.2 million of debt outstanding. Of this amount, $20.0 million bears interest at fixed rates of 5.15% after the effect of interest rate hedging. The remaining balance of approximately $7.2 million bears interest at floating rates, which averaged 6.4% at December 31, 2007. The 30-day LIBOR rate on December 31, 2007 was 4.6%.

Off-Balance Sheet Arrangements

We do not currently use any off-balance sheet arrangements to enhance our liquidity or capital resource position, or for any other purpose.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various risks, including energy commodity price risk. We expect energy prices to remain volatile and unpredictable. If energy prices were to decline significantly, revenues and cash flow would significantly decline, and our ability to borrow to finance our operations could be adversely impacted. We have designed our hedging policy to reduce the risk of price volatility for our production in the natural gas and crude oil markets. Our risk management policy provides for the use of derivative instruments to manage these risks. The types of derivative instruments that we use include swaps and collars. The volume of derivative instruments that we may use is governed by the risk management policy and can vary from year to year, but under most circumstances will apply to only a portion of our current and anticipated production and provide only partial price protection against declines in oil and natural gas prices. We are exposed to market risk on our open contracts, to the extent of changes in market prices of oil and natural gas. However, the market risk exposure on these hedged contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity that is hedged. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits of the hedges.

We are also exposed to market risk related to adverse changes in interest rates. Our interest rate risk exposure results primarily from fluctuations in short-term rates, which are LIBOR and prime rate, as determined by our lenders, based and may result in reductions of earnings or cash flows due to increases in the interest rates we pay on these obligations.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REX ENERGY CORPORATION

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and
Stockholders of
Rex Energy Corporation
State College, Pennsylvania

We have audited the accompanying consolidated and combined balance sheets of Rex Energy Corporation and Predecessor Companies as of December 31, 2007 and 2006 and the related consolidated and combined statements of operations, owners' equity (deficit) and minority interests, and cash flows for each of the years in the three-year period ended December 31, 2007. Rex Energy Corporation's management is responsible for these financial statements. 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the company's internal control over financial reporting. Accordingly, we do not express such an opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated and combined financial position of Rex Energy Corporation and Predecessor Companies as of December 31, 2007 and 2006, and the consolidated and combined results of operations, owners' equity (deficit) and minority interest, and cash flows for each of the years in the three-year period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

Malin, Bergquist & Company, LLP
Pittsburgh, Pennsylvania
March 31, 2008

REX ENERGY CORPORATION

CONSOLIDATED AND COMBINED BALANCE SHEETS
($ in Thousands)

	Rex Energy Corporation Consolidated December 31, 2007	Predecessor Companies Combined December 31, 2006
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 1,085	$ 600
Related Party Receivable	—	2
Accounts Receivable	8,805	6,884
Short-Term Derivative Instruments	20	1,275
Deferred Taxes	4,700	—
Inventory and Prepaid Expenses	1,388	904
Total Current Assets	15,998	9,665
Property and Equipment (Successful Efforts Method)		
Evaluated Oil and Gas Properties	200,962	127,370
Unevaluated Oil and Gas Properties	33,074	14,569
Other Property and Equipment	4,397	4,182
Wells and Other Work in Progress	10,773	3,460
Pipelines	2,194	1,765
Total Property and Equipment	251,400	151,346
Less: Accumulated Depreciation, Depletion and Amortization	(33,868)	(17,715)
Net Property and Equipment	217,532	133,631
Intangible and Other Assets—Net	2,034	1,172
Long-Term Derivative Instruments	—	143
Goodwill	32,700	—
Total Assets	$268,264	$144,611
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts Payable	$ 7,152	$ 4,425
Accrued Expenses	2,662	3,911
Short-Term Derivative Instruments	10,893	2,978
Accrued Distributions	—	102
Current Lines of Credit	—	37,581
Current Portion of Long-Term Debt	29	2,867
Related Party Payable	—	1,820
Total Current Liabilities	20,736	53,684
Long-Term Debt and Other Loans and Notes Payable	27,207	45,442
Long-Term Derivative Instruments	18,843	1,698
Participation Liability	—	2,141
Long-Term Deferred Taxes	30,300	—
Other Deposits and Liabilities	345	405
Future Abandonment Cost	6,396	5,269
Total Liabilities	103,827	$108,639
Commitments and Contingencies (See Notes)		
Minority Interests	—	36,589
Owners' Equity		
Common Stock, $.001 par value per share, 100,000,000 shares authorized and 30,794,702 shares issued and outstanding on December 31, 2007	31	1
Additional Paid-In Capital	175,170	1,460
Retained (Deficit)	(10,640)	(581)
Other Comprehensive (Loss)	(124)	—
Partner's and Member's (Deficit)	—	(1,497)
Total Owners' Equity (Deficit)	164,437	(617)
Total Liabilities, Minority Interests and Owners' Equity (Deficit)	$268,264	$144,611

See accompanying notes

REX ENERGY CORPORATION

CONSOLIDATED AND COMBINED STATEMENT OF OPERATIONS
($ and Shares in Thousands Except per Share Data)

	Rex Energy Corporation Consolidated and Combined	Rex Energy Combined Predecessor Companies	Rex Energy Combined Predecessor Companies
	Year Ended December 31,		
	2007	2006	2005
OPERATING REVENUE			
Oil and Natural Gas Sales	$ 63,525	$43,596	$29,518
Other Revenue	452	470	270
Realized Gain(Loss) on Derivatives	(6,198)	(4,436)	(7,930)
TOTAL OPERATING REVENUE	57,779	39,630	21,858
OPERATING EXPENSES			
Production and Lease Operating Expenses	23,691	14,683	11,255
Production Taxes	786	551	466
General and Administrative Expense	8,587	6,212	3,789
Accretion Expense on Asset Retirement Obligation	640	476	200
Exploration Expense of Oil and Gas Properties	2,948	—	107
Depreciation, Depletion, and Amortization	18,982	10,747	3,120
TOTAL OPERATING EXPENSES	55,634	32,669	18,937
INCOME FROM OPERATIONS	2,145	6,961	2,921
OTHER INCOME (EXPENSE)			
Interest Income	15	94	444
Interest Expense	(5,646)	(6,110)	(1,697)
Gain on Sale of Oil and Gas Properties	185	91	1,016
Unrealized (Loss) Gain on Derivatives	(26,250)	5,043	(5,541)
Other Income (Expense)	171	(132)	216
TOTAL OTHER INCOME (EXPENSE)	(31,525)	(1,014)	(5,562)
NET INCOME (LOSS) BEFORE MINORITY INTEREST AND (PROVISION) BENEFIT FOR TAXES	(29,380)	5,947	(2,641)
MINORITY INTEREST SHARE OF (NET INCOME) LOSS	6,152	(2,133)	(2,304)
NET INCOME (LOSS) BEFORE INCOME TAX	(23,228)	3,814	(4,945)
Income Tax Benefit (Expense)	7,017	—	—
NET INCOME (LOSS)	$(16,211)	$ 3,814	$ (4,945)
Earnings per common share for the five month period ended December 31, 2007:			
Net loss for the five month period ended December 31, 2007	$(10,640)	—	—
Basic and fully diluted earnings per share	$ (0.35)	—	—
Weighted average shares of common stock outstanding	30,795	—	—

See accompanying notes

REX ENERGY CORPORATION

CONSOLIDATED AND COMBINED STATEMENT OF CHANGES IN OWNERS' EQUITY (DEFICIT) AND MINORITY INTERESTS
($ in Thousands)

	Common Stock	Additional Paid In Capital	Retained Earnings	Other Comprehensive Income	Members' Equity	Partners' Equity	Total Owners' Equity	Minority Interests
BALANCE December 31, 2004	$—	$ —	$ —	$ —	—	$ 3,198	$ 3,198	$ 11,696
CAPITAL CONTRIBUTIONS	1	1,460	4,502	—	21	1,261	7,245	13,384
DISTRIBUTIONS	—	—	(3,919)	—	—	(1,745)	(5,664)	(2,583)
PARTNERSHIP REDEMPTION	—	—	—	—	—	(10,754)	(10,754)	(671)
NET INCOME (LOSS)	—	—	(4,325)	—	—	(620)	(4,945)	2,304
BALANCE December 31, 2005	1	1,460	(3,742)	—	21	(8,660)	(10,920)	24,130
CAPITAL CONTRIBUTIONS	—	—	—	—	6,974	1,887	8,861	14,099
DISTRIBUTIONS	—	—	(55)	—	—	(2,317)	(2,372)	(3,773)
NET INCOME (LOSS)	—	—	3,217	—	(1,026)	1,623	3,814	2,133
BALANCE December 31, 2006	1	1,460	(580)	—	5,969	(7,467)	(617)	36,589
NET INCOME (LOSS) Before reorganization	—	—	373	—	(4,002)	(1,943)	(5,572)	(6,152)
CAPITAL CONTRIBUTIONS Before reorganization	—	—	—	—	—	820	820	300
DISTRIBUTIONS Before reorganization	—	—	—	—	—	(294)	(294)	(1,830)
REDEMPTION Before reorganization	—	—	—	—	—	—	—	(7,970)
REORGANIZATION and acquisition of minority interests effected through the exchange of 21,994,702 shares of common stock for partnership interests and shares of Predecessor Companies to Rex Energy Corporation	21	85,667	207	—	(1,967)	8,884	92,812	(20,937)
ISSUANCE of 8,800,000 shares of common stock net of issuance costs of $2.6 million	9	87,831	—	—	—	—	87,840	—
Unrealized loss on interest rate swap agreements, net of tax of $84	—	—	—	(124)	—	—	(124)	—
Non-cash compensation expense	—	212	—	—	—	—	212	—
NET LOSS after reorganization	—	—	(10,640)	—	—	—	(10,640)	—
BALANCE December 31, 2007	$ 31	$175,170	$(10,640)	$(124)	—	$ —	$164,437	$ —

See accompanying notes

REX ENERGY CORPORATION

CONSOLIDATED AND COMBINED STATEMENT OF CASH FLOWS
(Unaudited, $ in Thousands)

	Rex Energy Corporation Consolidated and Combined	Rex Energy Combined Predecessor Companies	Rex Energy Combined Predecessor Companies
	For the Years Ended December 31,		
	2007	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES			
Net (Loss) Income	$ (16,211)	3,814	(4,945)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities			
Minority Interest Share of (Loss) Income	(6,152)	2,133	2,304
Non-cash compensation Expense	212	—	—
Depreciation, Depletion, and Amortization	18,982	10,745	3,120
Deferred Income Tax Benefit	(7,017)	—	—
Unrealized Loss (Gain) on Derivatives	26,250	(5,043)	5,541
Exploration Expense	2,948	—	107
Accretion Expense on Asset Retirement Obligation	640	476	200
Bad Debt Expense	12	76	6
Amortization of Participation Liability	—	1,567	444
(Gain) on Sale of Oil and Gas Properties	(185)	(91)	(1,017)
Changes in operating assets and liabilities, net of effects from acquisitions			
Accounts Receivable	(1,931)	(1,536)	(1,418)
Inventory, Prepaid Expenses and Other Assets	132	(118)	892
Accounts Payable and Accrued Expenses	26	611	4,403
Net Changes in Other Assets and Liabilities	(151)	286	(110)
NET CASH PROVIDED BY OPERATING ACTIVITIES	17,555	12,920	9,527
CASH FLOWS FROM INVESTING ACTIVITIES			
Proceeds from the Sale of Oil and Gas Properties, Prospects and Other Assets	239	157	3,291
Acquisitions of Oil & Gas Properties and Related Equipment	(7,663)	(79,750)	(18,647)
Capital Expenditures for Development of Oil & Gas Properties and Equipment	(32,678)	(14,853)	(4,048)
NET CASH USED IN INVESTING ACTIVITIES	(40,102)	(94,446)	(19,404)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from Long-Term Debts and Other Loans and Notes Payable	46,615	87,465	1,901
Repayments of Long-Term Debts and Other Loans and Notes Payable	(105,269)	(10,864)	(5,017)
Net (Repayments to) Proceeds from Related Parties	(1,000)	(6,316)	9,851
Repayment of Participation Liability	(2,141)	—	—
Debt Issuance Costs	(1,222)	(1,701)	—
Proceeds from the Issuance of Common Stock, Net of Issuance Costs	87,860	—	—
Capital Contributions by the Partners of the Predecessor Companies	300	18,383	16,315
Cash Distributions to the Partners of the Predecessor Companies	(2,111)	(7,529)	(13,278)
NET CASH PROVIDED BY FINANCING ACTIVITIES	23,032	79,438	9,772
NET (DECREASE) INCREASE IN CASH	485	(2,088)	(105)
CASH—BEGINNING	600	2,688	2,793
CASH—ENDING	$ 1,085	600	2,688
SUPPLEMENTAL DISCLOSURES			
Cash Paid for Income Taxes	—	—	—
Interest Paid	5,918	6,544	1,236
NON-CASH ACTIVITIES			
Redemption-Property Distribution	7,970	—	3,759
Conversion of Loan Payable to Capital	820	—	—
Loan Repayment and Non-Cash Distributions to Lance T. Shaner	—	1,715	3,270
Accrued Distribution	—	102	428
Loan Costs Paid by Line of Credit Draws	—	506	—
NON-CASH ACTIVITIES RELATED TO THE REORGANIZATION:			
Step-Up of Asset Basis Resulting from the Acquisition of Minority Interests	71,876	—	—
Recordation of Goodwill	32,700	—	—

See accompanying notes

REX ENERGY CORPORATION AND PREDECESSOR COMPANIES
NOTES TO THE CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION AND PRINCIPLES OF CONSOLIDATION

Rex Energy Corporation is an independent oil and gas company operating in the Illinois Basin, the Appalachian Basin and the Southwestern Region of the United States. We pursue a balanced growth strategy of exploiting our sizeable inventory of lower risk developmental drilling locations, pursuing our higher potential exploration drilling prospects and actively seeking to acquire complementary oil and natural gas properties.

We refer to certain companies—Douglas Oil & Gas Limited Partnership, Douglas Westmoreland Limited Partnership, Midland Exploration Limited Partnership, New Albany-Indiana, LLC, PennTex Resources, L.P., PennTex Resources Illinois, Inc., Rex Energy Limited Partnership, Rex Energy II Limited Partnership, Rex Energy III LLC, Rex Energy IV, LLC, Rex Energy II Alpha Limited Partnership, Rex Energy Operating Corp. and Rex Energy Royalties Limited Partnership—collectively as the "Predecessor Companies." We refer to each of the Predecessor Companies individually as:

Douglas Oil & Gas Limited Partnership	"Douglas Oil & Gas"
Douglas Westmoreland Limited Partnership	"Douglas Westmoreland"
Rex Energy Royalties Limited Partnership	"Rex Royalties"
Midland Exploration Limited Partnership	"Midland"
New Albany-Indiana, LLC	"New Albany"
PennTex Resources Illinois, Inc	"PennTex Illinois"
PennTex Resources, L.P	"PennTex Resources"
Rex Energy Limited Partnership	"Rex I"
Rex Energy II Limited Partnership	"Rex II"
Rex Energy II Alpha Limited Partnership	"Rex II Alpha"
Rex Energy III LLC	"Rex III"
Rex Energy IV, LLC	"Rex IV"
Rex Energy Operating Corp	"Rex Operating"

Simultaneously with the consummation of our initial public offering of common stock, through a series of mergers and reorganization transactions, which we refer to as the "Reorganization Transactions," Rex Energy Corporation acquired all of the outstanding equity interests of the Predecessor Companies. Unless otherwise indicated, all references to "Rex Energy Corporation," "our," "we," "us" and similar terms refer to Rex Energy Corporation and subsidiaries together with the Predecessor Companies, after giving effect to the Reorganization Transactions.

The accompanying consolidated and combined financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and include (1) subsequent to the reorganization as described below, the consolidated accounts of Rex Energy Corporation and (2) prior to the reorganization the Predecessor Companies, the combined accounts of the Predecessor Companies under the common ownership of Lance T. Shaner. The consolidated and combined financial statements include the accounts of all of our subsidiaries. Investments in entities over which we have a significant influence, but not control, are accounted for using the equity method of accounting, are carried at our share of net assets and are included in other assets on the balance sheet. Income from equity method investments represents our proportionate share of income generated by equity method investees and is included in other revenue on our consolidated statement of operations. All material intercompany balances and transactions have been eliminated.

The combined financial statements of the Predecessor Companies reflect the assets, liabilities, revenues, expenses and cash flows on a gross basis, and the economic interests not owned by Lance T. Shaner are reflected as minority interests. All of the Predecessor Companies were under the common control of Lance T. Shaner, our Chairman, through his direct and indirect ownership interests and other contractual arrangements, as well as under the common management of Rex Energy Operating Corp.

On July 30, 2007, we reorganized by acquiring all of the outstanding equity interests of each of the Predecessor Companies through a series of mergers and reorganization transactions (the "Reorganization Transactions"). The Reorganization Transactions occurred simultaneously with the consummation of our initial public offering of common stock. The Reorganization Transactions were accounted for partially as an exchange of entities under common control for the interests in the Predecessor Companies which were contributed by Lance T. Shaner, and partially as an acquisition of minority interests using the purchase method of accounting for all the predecessor owners other than Lance T. Shaner pursuant to Statement of Financial Accounting Standards ("SFAS") No. 141, *Business Combinations* ("SFAS No. 141").

The initial public offering of shares of common stock consisted of 8,800,000 shares of common stock offered and sold by us at an offering price of $11.00 per share. We received gross proceeds from the offering of $96.8 million and incurred approximately $9.0 million in underwriting discounts, commissions, and offering costs associated with the offering.

The Reorganization Transactions resulted in our recognition of the acquisition of minority ownership interests and an associated increase in the book basis of certain property assets. These assets are subject to depletion and amortization expenses. The reorganization also resulted in our becoming subject to federal and state income taxes. Tax expenses had previously passed through to the equity owners of the Predecessor Companies and were not recorded on the books of the Predecessor Companies.

Certain amounts have been reclassified in prior periods to conform to the current year presentation. The December 31, 2006 and 2005 Combined Statement of Operations and Cash Flow Statement lines titled "Impairment of Oil and Gas Properties" have been modified to "Exploration Expense of Oil and Gas Properties" to more accurately reflect the nature of these expenditures. Unrealized Loss (Gain) on Derivatives has been reclassified from Operating Revenue to Other Income (Expense) to be more consistent with income statement presentations of such items common to the oil and natural gas exploration industry. Certain assets approximating $616,000 related to drilling equipment and repair were recognized as inventory on the December 31, 2006 balance sheet and have been subsequently reclassified as wells in progress.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the periods reported. Actual results could differ from these estimates.

Significant estimates made in preparing these consolidated and combined financial statements include, among other things, estimates of the proved oil and natural gas reserve volumes used in calculating DD&A expense; the estimated future cash flows and fair value of properties used in determining the need for any impairment write-down; fair values of financial derivative instruments; volumes and prices for revenues accrued; estimates of the fair value of equity-based compensation awards; deferred tax valuation; and the timing and amount of future abandonment costs used in calculating asset retirement obligations. Future changes in the assumptions used could have a significant impact on reported results in future periods. The significant estimates are based on current assumptions that may be materially effected by changes to future economic conditions such as the market prices received for sales of volumes of oil and natural gas, interest rates, and our ability to generate future income.

Cash and Cash Equivalents

We consider all highly liquid investments with original maturity of three months or less when purchased to be cash equivalents.

Accounts Receivable

Our trade accounts receivable, which are primarily from oil and natural gas sales, are recorded at the invoiced amount and include production receivables. The production receivable is valued at the invoiced amount and does not bear interest. Accounts receivable also includes joint interest billing receivables which represent billings to the non-operators associated with the operation of wells and are based on those owners' working interests in the wells. We have assessed the financial strength of our customers and joint owners and recorded bad debts as necessary.

We use the allowance method to account for uncollectible accounts receivable. A reserve is recorded for amounts we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted. The reserve of $150,000 at January 1, 2006 increased by $76,000 due to bad debt expense and was reduced by $53,000 of write offs during calendar year 2006. The reserve of $173,000 at January 1, 2007 increased by $12,000 of bad debt expense and there were no write offs during calendar year 2007. Accordingly, the allowance for uncollectible receivables was $185,000 at December 31, 2007.

To the extent actual quantities and values of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and price for those properties are estimated and recorded as "Accounts receivable" in the accompanying financial statements.

At December 31, 2007, we carried approximately $8.1 million in accounts receivable, of which approximately $5.4 million were production receivables due from a single customer, Countrymark Cooperative LLP.

Inventory

Inventory is valued at the lower of cost or market value and consists of our ownership interest in oil held in terminal tanks located in the field. Oil inventory is accounted for using the average cost method with average cost defined as production and lease operating expenses net of depreciation, depletion, and amortization. General and Administrative expenses are not allocated to the cost of inventory for the purpose of valuing inventory.

Oil and Natural Gas Property, Depreciation and Depletion

We account for natural gas and oil exploration and production activities under the successful efforts method of accounting. Proved developed natural gas and oil property acquisition costs are capitalized when incurred. Unproved properties with individually significant acquisition costs are assessed quarterly on a property-by-property basis, and any impairment in value is recognized. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved natural gas and oil properties. Natural gas and oil exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether they have discovered proved commercial reserves. If proved commercial reserves are not discovered, such drilling costs are expensed. Costs to develop proved reserves, including the costs of all development well and related equipment used in the production of natural gas and oil are capitalized.

Depletion, depreciation and amortization are calculated using the unit-of-production method on estimated proved oil and gas reserves at the lease or well level. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. We periodically review estimated proved reserve estimates and makes changes as needed to depletion, depreciation and amortization expenses to account for new wells drilled, acquisitions, divestitures and other events which may have caused significant changes in our estimated proved developed producing reserves. The costs of unproved properties are withheld from the depletion base until such time as they are either developed or abandoned. When proved reserves are assigned or the property is considered

to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion calculations. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Undeveloped leasehold cost is allocated to the associated producing properties as the undeveloped acreage is developed. Individually significant non-producing properties are periodically assessed for impairment of value. Service properties, equipment and other assets are depreciated using the straight-line method over their estimated useful lives of 3 to 30 years.

We account for impairment under the provisions of SFAS No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets*." When circumstances indicate that an asset may be impaired, we compare expected undiscounted future cash flows at a producing field to the unamortized capitalized cost of the asset. If the future undiscounted cash flows, based on our estimate of future natural gas and oil prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate. At December 31, 2007 oil and gas properties valued at $642,000 were impaired and included in depreciation, depletion, and amortization on the consolidated and combined statement of operations for the year ended December 31, 2007. The impairment expense represents 100% of the carrying value of those assets associated with a coalmine methane project in West Virginia for which we can no longer identify a suitable market for the methane gas produced by the mine.

Expenditures for repairs and maintenance to sustain or increase production from the existing producing reservoir are charged to expense as incurred. Expenditures to recomplete a current well in a different unproved reservoir are capitalized pending determination that economic reserves have been added. If the recompletion is not successful, the expenditures are charged to expense.

Significant tangible equipment added or replaced that extends the useful or productive life of the property is capitalized. Expenditures to construct facilities or increase the productive capacity from existing reservoirs are capitalized.

Upon the sale or retirement of a proved natural gas or oil property, or an entire interest in unproved leaseholds, the cost and related accumulated depreciation, depletion, and amortization are removed from the property accounts and the resulting gain or loss is recognized. For sales of a partial interest in unproved leaseholds for cash or cash equivalents, sales proceeds are first applied as a reduction of the original cost of the entire interest in the property and any remaining proceeds are recognized as a gain.

Natural Gas and Oil Reserve Quantities

Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. For the year ended December 31, 2005, our independent engineering firm, Netherland, Sewell & Associates, Inc., prepared a reserve and economic evaluation of each of the Predecessor Companies' proved oil and gas reserves which has been combined by us to determine our total proved oil and gas reserves for the period. For the year ended December 31, 2007 and 2006, Netherland, Sewell & Associates, Inc. prepared a consolidated reserve and economic evaluation of our proved oil and gas reserves.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. We prepare reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. Our independent engineering firm adheres to the same guidelines when preparing their reserve reports. The accuracy of our reserve estimates is a function of many factors, including the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates. Any of the assumptions inherent in

these factors could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of natural gas and oil eventually recovered. The independent reserve engineer estimates reserves annually on December 31. This annual estimate results in a new DD&A rate which we use for the preceding fourth quarter after adjusting for fourth quarter production.

Goodwill and Intangible Assets

In accordance with SFAS No. 142, "*Goodwill and Other Intangible Assets*" ("SFAS 142") no amortization is recorded for goodwill or intangible assets deemed to have indefinite lives for acquisitions completed after June 30, 2001. SFAS No. 142 requires that goodwill and non-amortizable assets be assessed annually for impairment. At December 31, 2007, our intangible assets consist of $32.7 million of goodwill and $1.3 million of intangible assets comprised of sales agreements that are amortized over an estimated useful life of five years. These goodwill and intangible assets resulted from the Reorganization Transactions (see Note 1). For the years ended December 31, 2007, 2006, and 2005, we recorded amortization expense of $111,000 $0 and $0, respectively. Amortization expenses were recorded only for those periods following the Reorganization Transactions.

Goodwill and identified intangible assets that have an indefinite useful life are subject to impairment testing, which we conduct annually, or on an interim basis if events or changes in circumstances between annual tests indicate the assets might be impaired. We perform our annual impairment test for goodwill and identified intangible assets that have an indefinite useful life as of December 31 of each year. The impairment test involves a comparison of the fair value of each tangible and intangible asset to its carrying value. If the fair value is less than the carrying value, a further test is required to measure the amount of impairment. As of December 31, 2007 there was no impairment indicated by our analysis.

Future Abandonment Cost

We account for future abandonment costs using SFAS No. 143, *"Asset Retirement Obligations"* ("SFAS No. 143"). This statement applies to obligations associated with the retirement of tangible long-lived assets that result from the acquisition and development of the asset. SFAS No. 143 requires that the fair value of a liability for a retirement obligation be recognized in the period in which the liability is incurred. For natural gas and oil properties, this is the period in which the natural gas or oil well is acquired or drilled. The future abandonment cost is capitalized as part of the carrying amount of our natural gas and oil properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the natural gas or oil well is sold, at which time the liability is reversed.

	December 31, 2007 ($ in Thousands)	**December 31, 2006 ($ in Thousands)**
Beginning Balance	$5,269	$2,358
Initial Asset Retirement Obligation Capitalized	506	2,506
Plugging Costs Incurred	(19)	(71)
Asset Retirement Obligation Accretion Expense	640	476
Total Asset Retirement Obligation	$6,396	$5,269

Accumulated Other Comprehensive Income (Loss)

We follow the provisions of SFAS No. 130, "*Reporting Comprehensive Income,*" which establishes standards for reporting comprehensive income. Comprehensive income includes net income as well as all changes in equity during the period, except those resulting from investments and distributions to owners and equaled a loss of $16.3 million for the year ended December 31, 2007.

At December 31, 2007, we had a $208,000 pre-tax loss ($124,000 net of tax effect of $84,000) in other comprehensive income ("OCI") relating to unrealized interest rate hedges and no gain or loss in OCI as of December 31, 2006. There were no reclassifications from OCI into earnings during the year ended December 31, 2007.

Revenue Recognition

Oil and Natural gas revenue is recognized when the oil or natural gas is delivered to or collected by the respective purchaser, a sales agreement exists, collection for amounts billed is reasonably assured, and the sales price is fixed or determinable. Title to the produced quantities transfers to the purchaser at the time the purchaser collects or receives the quantities. In the case of oil sales, title is transferred to the purchaser when the oil leaves our stock tanks and enters the purchaser's trucks. In the case of gas production, title is transferred when the gas passes through the meter of the purchaser. It is the measurement of the purchaser that determines the amount of oil or gas purchased (although there are provisions for challenging these measurements if we believe the measuring instruments are faulty). Prices for such production are defined in sales contracts and are readily determinable based on certain publicly available indices. The purchasers of such production have historically made payment for oil and natural gas purchases within 30-60 days of the end of each production month. We periodically review the difference between the dates of production and the dates we collect payment for such production to ensure that receivables from those purchasers are collectible. The point of sale for our oil and natural gas production is at its applicable field gathering system; therefore, we do not incur transportation costs related to our sales of oil and natural gas production. We do not currently participate in any gas-balancing arrangements. We do not recognize revenue for oil production held in stock tanks before delivery to the purchaser.

To the extent actual quantities and values of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and price for those properties are estimated and recorded as "Accounts receivable" in the accompanying financial statements.

Derivative Instruments

We use put and call options (collars) and fixed rate swap contracts to manage price risks in connection with the sale of oil and natural gas. We also utilize interest-rate swap agreements to manage interest-rate risks associated with our variable-rate credit facility. We account for these collar and swap contracts using Statement of Financial Accounting Standards No. 133, *"Accounting for Derivative Instruments and Hedging Activities*"("SFAS No. 133"). We elect not to use hedge accounting for commodity derivative contracts, and unrealized gains or losses are shown in other income and expense on our Consolidated and Combined Statement of Operations. Realized gains and losses are shown in operating revenue on the Consolidated and Combined Statement of Operations.

We have established the fair value of all derivative instruments using estimates determined by our counterparties. These values are based upon, among other things, future prices, volatility, time to maturity, and credit risk. The values we report in our consolidated financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

SFAS No. 133 establishes accounting and reporting standards requiring derivative instruments (including certain derivative instruments embedded in other contracts or agreements) be recorded at fair value and included in the Consolidated Balance Sheets as assets or liabilities. The accounting for changes in fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any changes in fair value resulting from ineffectiveness, as defined by SFAS No. 133, is recognized immediately in earnings.

For derivative instruments designated as fair value hedges (in accordance with SFAS No. 133), changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings. Derivative effectiveness is measured annually based on the relative changes in fair value between the derivative contract and the hedged item over time. For derivatives on oil and natural gas production activity, our evaluations are not documented, and as a result, we record changes on the derivative valuations through earnings.

Advertising Expense

Advertising costs are expensed as incurred and were approximately $27,000, $39,000 and $23,000 for the years ended December 31, 2007, 2006, and 2005, respectively.

Loan Costs

Loan costs consist of gross debt issuance costs of approximately $690,000 and $1,752,000 at December 31, 2007 and 2006 that are presented net of accumulated amortization of $42,000 and $608,000, respectively. Loan costs at December 31, 2007 are included in Other Assets on the Combined Balance Sheet, and are amortized over five years.

Stock-based Compensation

We account for stock-based compensation under the provisions of SFAS No. 123(R), "*Share-Based Payment"* ("SFAS 123R"), which requires us to recognize in the financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. We use a standard option pricing model (i.e. Black-Scholes) to measure the fair value of employee stock options under SFAS 123R.

SFAS 123R also requires that the benefits associated with the tax deductions in excess of recognized compensation cost be reported as a financing cash flow. This requirement reduces net operating cash flows and increases net financing cash flows. We recognize compensation costs related to awards with graded vesting on a straight-line basis over the requisite service period for each separately vesting portion of the award as if the award was, in-substance, multiple awards.

For the year ended December 31, 2007 we recognized $211,000 in expense related to stock option grants which was recorded on our Consolidated and Combined Statement of Operations under the heading of general and administrative expense.

Earnings Per Share

Earnings per common share is computed by dividing consolidated net income by the weighted average number of common shares outstanding. Diluted earnings per common share is computed by dividing consolidated net income by the weighted average number of common shares outstanding during the period, including any potentially dilutive outstanding securities, such as options and warrants. Earnings per share is reflected prospectively from August 1, 2007, the date the Predecessor Companies were acquired by Rex Energy Corporation. Therefore, at December 31, 2007, we had consolidated operations for only five months in the fiscal year period for which earnings per share are relevant. At December 31, 2007, we had 30,794,720 common shares outstanding, 815,000 options outstanding and no outstanding warrants, or other potentially dilutive securities. In March 2008, 25,000 of the options outstanding on December 31, 2007 were voluntarily forfeited.

Before the Reorganization Transactions, our business was conducted through a group of entities as to which there was no single holding entity. Each entity was separately owned by its then existing owners. As a result there was no single capital structure upon which to calculate historical earnings per share information. Accordingly, earnings per share information has not been presented for historical periods before the Reorganization.

Recently Issued Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, *"Fair Value Measurements" ("SFAS 157"),* which provides guidance for using fair value to measure assets and liabilities. SFAS 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value and clarifies that for items that are not actively traded, such as certain kinds of derivatives, fair value should reflect the price in a transaction with a market participant, including an adjustment for risk, not just the company's mark-to-model value. SFAS 157 also requires expanded disclosure of the effect on earnings for items measured using unobservable data. SFAS 157 is effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Consequently, we will adopt the provisions of SFAS 157 for the year beginning January 1, 2008. We are currently evaluating the effect that the implementation of SFAS 157 will have on our results of operations and financial condition, but we do not expect it will have a material impact.

On February 15, 2007, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standard ("SFAS") No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities—Including an Amendment of SFAS No. 115*. SFAS No. 159 permits an entity to choose to measure many financial instruments and certain other items at fair value. Under SFAS No. 159, a business entity is required to report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. SFAS No. 159 is effective as of January 1, 2008. We are currently evaluating the effect that the implementation of SFAS 159 will have on our results of operations and financial condition, but do not expect it will have a material impact.

In April 2007, the FASB issued FASB Staff Position ("FSP") on FASB Interpretation ("FIN") 39—1, *"Amendment of FASB Interpretation No. 39" ("FSP FIN 39-1")*, to permit a reporting entity that is party to a master netting arrangement to offset the fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement in accordance with FIN 39. FSP FIN 39—1 is effective for fiscal years beginning after November 15, 2007. We do not expect the implementation of FSP FIN 39—1 will have a material impact on our results of operations or financial condition.

In May 2007, the FASB issued FSP FIN 48-1, *"Definition of Settlement in FASB Interpretation No. 48"*, which amends FIN No. 48, *"Accounting for Uncertainty in Income Taxes—an Interpretation of FASB Statement No. 109"* ("FIN 48"), to provide guidance on how an entity should determine whether a tax position is effectively settled for the purpose of recognizing previously unrecognized tax benefits. FSP FIN 48-1 clarifies that a tax position is effectively settled for the purpose of recognizing previously unrecognized tax benefits if the taxing authority has completed all of its required or expected examination procedures, the enterprise does not intend to appeal or litigate any aspect of the tax position, and it is considered remote that the taxing authority would reexamine the tax position. This guidance is effective upon initial adoption of FIN 48, which we adopted for the year ending December 31, 2007. The Predecessor Companies were treated as pass through entities for federal and state income tax purposes, therefore, the adoption of FIN 48 did not have an impact on results of operations and financial condition for the seven month periods ended July 31, 2007. We have evaluated the effects of FIN 48 and FSP FIN 48-1 upon the completion of the Reorganization Transactions, on July 30, 2007 and again as of December 31, 2007, and have determined they do not currently have a material impact on the results of operations or financial condition.

In December 2007, the FASB issued SFAS No. 160, *"Noncontrolling Interests in Consolidated Financial Statements" ("SFAS 160")*, which provides direction on reporting minority (noncontrolling) interests in the consolidated financial statements. The standards set forth in SFAS No. 160 include clearly identifying and labeling noncontrolling interests in the consolidated statement of equity, separate from the parent's equity; clearly identifying consolidated net income of the parent and the noncontrolling interests on the consolidated statement of income; consistently accounting for changes in the parent ownership interest when the parent preserves its controlling interest; any retained noncontrolling equity investment of a deconsolidated subsidiary

and any resulting gain or loss will be measured using fair value and; disclosures must provide a level of detail that clearly identifies and separates the interests of the parent and the interest of the noncontrolling owners. SFAS 160 is effective for fiscal years beginning on or after December 15, 2008, and interim periods within those fiscal years. We are currently evaluating the effect that the implementation of SFAS 160 will have on our results of operations and financial condition, but do not expect it will have a material impact.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), "*Business Combinations*" ("SFAS 141R"). SFAS 141R is a revision of SFAS No. 141, "*Business Combinations*" ("SFAS 141"). SFAS 141R amends SFAS 141 by requiring an acquirer to recognize" (i) the assets acquired, liabilities assumed, and any noncontrolling interest in the acquiree at fair value as of the acquisition date, (ii) a gain attributable to any "negative goodwill" in a bargain purchase, and (iii) an expense related to acquisition costs. SFAS 141R is effective for fiscal years beginning on or after December 15, 2008. We do not expect the adoption of SFAS 141R to have a material impact on current results of operations or financial condition. However, future results of operations or financial condition may be materially affected if we have a significant acquisition.

On December 21, 2007, the SEC staff released Staff Accounting Bulletin No. 110. The SAB allows registrants to continue to use the "simplified method" defined in SAB 107 for determining the expected term of "plain vanilla" options. Under FASB Statement No. 123R, "Share-Based Payment," expected term is one of the primary factors used to measure fair value and compensation expense of share option grants. In SAB 107, the staff stated that it would not expect registrants to use the simplified method for share option grants after December 31, 2007. SAB 110 removes the end date for use of the simplified method but establishes conditions for its use. The SAB is effective January 1, 2008. We are currently evaluating the effect of SAB 110 will have on our results of operations and financial condition, but do not expect it will have a material impact.

3. BUSINESS AND OIL AND GAS PROPERTY ACQUISITIONS

Acquisition of Minority Interests

Pursuant to the Reorganization Transactions, Rex Energy Corporation acquired interests in the Predecessor Companies from the predecessor owners. These interests were acquired through an exchange of common stock in Rex Energy Corporation.

These transactions have been accounted for partially as a transfer of interests under common control and, partially, as an acquisition of non-controlling interests in accordance with SFAS No. 141. The controlling interests of the Predecessor Companies were held by Lance T. Shaner. Those interests are reflected in the consolidated financial statements at the historical cost of the interests contributed. The non-controlling owner's interests are accounted for using the purchase method of accounting under SFAS No. 141 and reflected as minority interests in the consolidated financial statements at the fair value of the interests contributed since such holders did not control the Predecessor Companies before the Reorganization Transactions.

The total consideration paid for the minority interests was $92.8 million and reflects 8,437,521 shares of Rex Energy Corporation common stock, the fair value of which was based upon the initial public offering price of $11.00 per share of common stock. Accordingly, we have reflected the acquired tangible assets at the fair value of the consideration paid. The excess of the purchase price and deferred tax liabilities over the fair value of the tangible assets acquired approximates $34 million and has been included in the captions "Intangible and Other assets—net" and "Goodwill" on the accompanying financial statements.

The finite-lived intangible assets related to the contractual right to future sales revenue from sales agreements was $1.3 million. The residual amount representing the purchase price in excess of tangible and intangible assets (including a net deferred tax liability of $32.7 million) is $32.7 million and has been recorded as Goodwill.

We are in the early stages of gathering data and performing an analysis and evaluation of the assets and liabilities assumed as of the date of acquisition. We have preliminarily estimated the excess cost over the fair values of those assets and liabilities. To the extent that the estimates used in the preliminary purchase price allocation need to be adjusted we will do so upon making that determination but not later than one year from the date of acquisition. We have preliminarily determined the following fair values for the acquired assets and liabilities assumed as of the date of acquisition ($ in thousands).

Purchase Price	$ 92,813
Minority interests	20,937
Goodwill	32,700
Finite-Lived Intangible Assets/Contractual Rights	1,328
Fair Value of Evaluated Property Assets	52,362
Fair Value of Unevaluated Property Assets	18,186
Deferred Tax Asset	2,300
Deferred Tax Liability	(35,000)
Purchase Price Allocation	$ 92,813

The estimated useful lives of the finite-lived intangibles are expected to be five years. We amortize these finite-lived intangibles over their estimated useful lives using the straight line method.

2007 Acquisitions

On February 26, 2007, Rex II acquired a 90.0% working interest in six oil and gas leases covering properties located in Hardin County, Texas for $1,080,000, after which time the operations have been included with those of the Company. The acquisition included interests in three producing oil wells and related infrastructure and equipment. The interests were purchased from the Creditor's Trust for Central Utilities Production Corp., a creditor's trust established in connection with a bankruptcy case styled *In re Central Utilities Production Corp.*, Case No. 03-44067, filed in the United States Bankruptcy Court, Eastern District of Texas, Sherman Division. The effective date of the acquisition was February 1, 2007.

On April 17, 2007, Rex II acquired a 52.375%, and 83.707% working interest in two oil and gas leases covering properties located in Concho County, Texas for $890,000, after which time the operations have been included with those of the Company. The acquisition included interests in 10 producing oil wells, eight water injection wells, three water supply wells, eight shut-in wells and related infrastructure and equipment. The interests were purchased from various working interest owners, including the operator of the properties, Ultra Oil & Gas Inc. Ultra Oil & Gas Inc. acted as agent for the various sellers. The effective date of the acquisition was January 1, 2007.

On April 27, 2007, Rex II acquired 100% of the New Albany Shale formation rights covering approximately 10,000 acres underlying the oil producing fields acquired by Rex III from Team Energy, L.L.C. and its affiliates in 2006. The purchase price was $750,000. The acreage is located in Posey and Gibson Counties, Indiana and Lawrence County, Illinois. Before the acquisition, certain of the Predecessor Companies owned the mineral leasehold rights to all other depths on the properties.

On May 24, 2007, Rex II acquired a 40.0% working interest in certain undeveloped oil and gas leases covering approximately 18,000 gross acres located in Knox, Daviess, Sullivan and Greene Counties in the State of Indiana. The interests were acquired from HAREXCO, Inc., an Illinois corporation doing business in the State of Indiana under the assumed name of Harris Energy Company ("Harris Energy"), for a purchase price of $1,079,000. In connection with this sale, Harris Energy reserved a 4.0% of 40.0% overriding royalty interest in the conveyed properties and a 10.0% of 40.0% back-in-after-payout working interest in the first five net wells

drilled on the acquired properties or any other properties which are subsequently acquired by Rex II from Harris Energy. In connection with the closing, Rex II and Harris Energy entered into an exploration agreement, wherein the parties created an area of mutual interest in certain areas of the above counties, and a joint operating agreement, wherein Rex II was appointed the operator of the covered properties. Rex II also agreed to purchase from Harris Energy a 40.0% working interest in certain oil and gas leasehold interests covering up to 5,878 net acres located in Knox County, Indiana. Pursuant to the agreement between the parties, Rex II is obligated to purchase an interest in only those oil and gas leases which are acquired by Harris Energy on or before August 22, 2007. The purchase price for the interest in these leases is equal to 40.0% of the product of $100.00 and the number of net leasehold acres assigned to Rex II on the closing date. In the event that Rex II purchases an interest in any of these leases, Harris Energy will also be entitled to reserve and retain the same overriding royalty interest and the back-in-after-payout working interest described above.

On September 7, 2007, our wholly owned subsidiary, Rex Energy I, LLC, acquired a 30% working interest in certain undeveloped oil and gas leases covering approximately 70,322 gross acres located in Lawrence, Orange, Washington and Jackson Counties in the State of Indiana for a purchase price of $1,055,000. The interests were acquired from Aurora Oil & Gas Corporation pursuant to an option granted to New Albany on January 27, 2006, the predecessor in interest of Rex Energy I, LLC. In connection with this sale, Aurora reserved a 0.5% overriding royalty interest in the conveyed properties.

On October 12, 2007, our wholly owned subsidiary, Rex Energy I, LLC, acquired a 40% working interest in certain undeveloped oil and gas leases covering approximately 5,878 net acres located in Knox County in the State of Indiana. The interests were acquired from HAREXCO, Inc., an Illinois corporation doing business in the State of Indiana under the assumed name of Harris Energy Company (“Harris Energy”), for a purchase price of $235,000. In connection with this sale, Harris Energy reserved a 4.0% of 40.0% overriding royalty interest in the conveyed properties and a 10.0% of 40.0% back-in-after-payout working interest in the first five net wells drilled on the acquired properties, the properties previously acquired from Harris Energy on May 24, 2007, or any other properties which are subsequently acquired from Harris Energy. Rex Energy I, LLC was obligated to purchase the above interests pursuant to the terms of a purchase and sale agreement dated May 24, 2007, which was previously entered into by its predecessor in interest, Rex II.

On November 29, 2007 a wholly owned subsidiary of Rex Energy Corporation, R.E. Gas Development, LLC, acquired a 50% working interest in multiple leases covering approximately 16,460 gross and 8,230 net undeveloped acres in Butler and Beaver Counties in the State of Pennsylvania. The interests were purchased from Vista Resources, Inc., a Pittsburgh, PA private oil and gas company for $1,070,000.

On December 17, 2007 a wholly owned subsidiary of Rex Energy Corporation, R.E. Gas Development, LLC, acquired a 100% working interest in multiple leases covering approximately 4,421 gross and 4,088 net undeveloped acres in Clearfield County in the State of Pennsylvania. The interests were purchased from three Pennsylvania corporations, Shannon Land & Mining Company, Synergen, Inc. and Appalachian Land Company for $409,000.

2007 Dispositions

On February 21, 2007, Rex II and Rex II Alpha sold their interest in a well for $220,000 and recorded a total gain on sale in the amount of $173,000.

In 2007, we disposed of various pieces of drilling equipment and scrap inventory and recorded a net gain on sale the sale of those assets of $12,000.

2006 Acquisitions

On January 24, 2006, Rex II and Rex II Alpha acquired a combined 99.5% working interest from Westar Energy, Inc. in 12 oil and gas leases covering properties located in Glassrock, Midland, Reagan and Upton Counties, Texas, for $5,175,000, after which time the operations have been included with those of the Company. The acquisition included interests in 21 producing oil wells, and related infrastructure and equipment. The effective date of the acquisition was January 1, 2006.

On February 7, 2006, Rex II and Rex II Alpha acquired a combined average 49.75% working interests from Wadi Petroleum, Inc. in 62 oil and gas leases covering properties located in Terrell County, Texas, for $3,825,000, after which time the operations have been included with those of the Company. The acquisition included interests in 15 producing gas wells, and related infrastructure and equipment, including interests in a gas gathering system. The effective date of the acquisition was December 1, 2005.

On February 1, 2006, New Albany completed an acquisition of certain oil and gas leases and other associated rights from Aurora Energy Ltd. pursuant to a Purchase and Sale Agreement with Aurora dated November 15, 2005. Under this purchase agreement, New Albany purchased from Aurora an undivided 48.75% working interest (40.7% net revenue interest) in (i) leases covering approximately 58,200 acres in several counties in Indiana (the “Leases”) and (ii) all of Aurora’s rights under a Farmout and Participation Agreement with a third party. In addition, Aurora granted an option, exercisable by New Albany until August 1, 2007, to acquire at a fixed price per acre a fifty percent (50.0%) working interest in acreage leased or acquired by Aurora or its affiliates in certain other counties located in Indiana. The total purchase price for the acquisition of the working interests in the Leases and Aurora’s rights under the Farmout Agreement, together with Aurora’s grant of the Option, was $10,500,000. New Albany subsequently acquired, through several transactions, an additional 48.75% working interest in 63,648 gross acres as of December 31, 2006 for $1,473,000.

On March 3, 2006 New Albany completed an acquisition of certain oil and gas leases and other associated rights from Source Rock Resources, Inc. (“Source Rock”) pursuant to a Purchase and Sale Agreement with Source Rock. Pursuant to this purchase agreement, New Albany purchased from Source Rock an undivided 45.0% working interests in leases covering approximately 21,070 gross acres for $736,000. In addition, New Albany subsequently acquired through several transactions an additional 45.0% working interest in leases covering approximately 17,646 gross acres for $332,000 as of December 31, 2006.

In June 2006, Rex II acquired a 29.4% working interest from four individuals, which is referred to as the “Scaggs Acquisition” for $1,217,000.

On June 28, 2006, Rex III acquired average working interests of 72.0% in approximately 220 producing oil wells and related infrastructure and equipment located in Posey and Gibson Counties, Indiana, and Lawrence County, Illinois from Team Energy, L.L.C., an Illinois limited liability company (“Team Energy”) and certain other companies affiliated with Team Energy, after which time the operations have been included with those of the Company. The effective date of the acquisition was June 1, 2006. The total acquisition price was $22,702,000.

On October 3, 2006, Rex IV acquired average working interests of 49.0% in certain oil producing properties and related wells and equipment located in the Lawrence, West Kenner, and St. James fields in Illinois, and the El Nora field in Indiana (the “Illinois and Indiana Properties”) for $35,172,000 from TSAR Energy II, L.L.C. (“Tsar”) , after which time the operations have been included with those of the Company. The effective date of the acquisition was October 1, 2006. PennTex Resources and PennTex Illinois, companies affiliated with Rex IV, own average working interests of 25.0% and 26.0%, respectively, in the Illinois and Indiana Properties. PennTex Illinois is the operator of the Illinois and Indiana Properties. The acquisition of the working interest of Tsar in the Illinois and Indiana Properties by Rex IV was accounted for as a purchase.

2006 Dispositions

In May 2006, Douglas Oil & Gas sold a parcel of land in New Jersey for $157,000. Douglas Oil & Gas recorded a gain on sale of this undeveloped land of $91,000.

2005 Acquisitions

Effective January 1, 2005, Lance T. Shaner acquired 100.0% of the common stock of ERG Illinois, Inc., a Delaware Corporation, ("ERG"), from ERG Holdings, Inc. ("ERG Holdings") , after which time the operations have been included with those of the Company. ERG was the operator of jointly-owned oil producing properties located in the states of Illinois and Indiana and had a corresponding 26.0% working interest in those properties. Following the acquisition of common stock, ERG was renamed to PennTex Resources Illinois, Inc. The total purchase price was $5,962,000. The transaction was accounted for as a purchase, and the excess of the purchase price over the ERG equity was pushed down to the Balance Sheet of PennTex Illinois. The excess of the purchase price over the ERG reported equity of $1,460,000 was allocated to oil properties and reported as a credit to additional paid in capital. PennTex Illinois also assumed the outstanding derivative instrument liabilities (costless collars) of ERG. These derivatives had a fair value of ($1,365,000) at the acquisition date of January 1, 2005. PennTex Illinois recorded this liability at acquisition and recognized the amount as additional consideration of oil and gas properties.

On August 31, 2005, Rex II and Rex II Alpha acquired a combined 99.0% working interest from National Energy Corporation in four oil and gas leases covering properties located in Lawrence County, Illinois, for $1,293,000, after which time the operations have been included with those of the Company. The acquisition included interests in 37 producing oil wells and related infrastructure and equipment. The effective date of the acquisition was July 1, 2005.

On September 19, 2005, Rex II and Rex II Alpha acquired a combined working interest ranging from 20.5% to 65.5% from Western Oil Producers, Inc. in several oil and gas leases for properties located in Eddy and Lea Counties, New Mexico, for $2,077,000, after which time the operations have been included with those of the Company. The acquisition included interests in 15 producing oil and gas wells and related infrastructure and equipment. The effective date of the acquisition was August 1, 2005. Subsequently during 2006, Rex II purchased additional, non-operating working interests in the same properties. These interests were purchased from various sellers for approximately $1,000,000.

On September 19, 2005, Rex II and Rex II Alpha acquired a combined 99.9% working interest from Brandt B. Powell in 3 oil and gas leases covering properties located in Lawrence County, Illinois, for $74,000, after which time the operations have been included with those of the Company. The acquisition included interests in 33 producing oil wells and related infrastructure and equipment. The effective date of the acquisition was September 15, 2005.

On December 6, 2005, Rex II and Rex II Alpha acquired a combined 98.5% working interest from Hux Oil Corp. and Pioneer Oil Company, Inc. in several oil and gas leases and units covering properties located in Gallatin County, Illinois and Vigo, Sullivan and Posey Counties, Indiana, for $6,966,000, after which time the operations have been included with those of the Company. The acquisition included interests in 88 producing oil wells and related infrastructure and equipment. The effective date of the acquisition was December 1, 2005.

In addition to the acquisitions noted above, Rex II made various smaller acquisitions throughout the year ended December 31, 2005 that amounted to approximately $800,000.

2005 Dispositions

In January 2005, PennTex Resources sold its interests in the Black Fork Creek oil and gas field located in Smith County, Texas for $2,971,000. The sale resulted in a gain on disposal of $1,204,000.

In February 2005, Douglas Oil & Gas sold its remaining interests in the Trenton Black River Project for $550,000. This sale included Douglas Oil & Gas' interest in the wells and mineral leasehold acreage. Douglas Oil & Gas recorded a loss on sale of these oil and gas properties of $187,000 in 2005.

4. PARTNERSHIP REDEMPTIONS

On March 12, 2007, New Albany entered into an Extension Agreement with its 50.0% member, Baseline Oil & Gas Corp. ("Baseline"). Under the terms of the Extension Agreement, Baseline was granted a one week extension to March 16, 2007 to pay a mandatory capital call issued by New Albany to Baseline in the amount of $492,000. In addition, the Extension Agreement provided that in the event Baseline paid New Albany an additional $1,729,000 in outstanding capital calls by March 16, 2007, New Albany would redeem Baseline's 50.0% membership interest in New Albany pursuant to the terms of a mutually agreed upon redemption agreement. Under the terms of the form of redemption agreement, New Albany would agree that in exchange for the redemption of Baseline's 50.0% membership interest in New Albany, New Albany would assign 50.0% of its assets, including its leasehold mineral interests, to Baseline. The Extension Agreement provided that in the event that Baseline failed to pay all outstanding capital calls by March 16, 2007, New Albany, and its non-defaulting members, would be entitled to exercise the rights set forth in Section 3.3(a) of New Albany's limited liability company agreement dated November 25, 2005. Section 3.3(a) provides that in the event a member fails to pay certain mandatory capital calls issued by the managing member of New Albany, New Albany may permit other non-defaulting members to contribute the amount owed by the defaulting member as an additional capital contribution to New Albany. In such event, the membership interests of all members of New Albany will be adjusted pursuant to a formula, the numerator of which is the member's total capital contributions to New Albany, and the denominator of which is the sum of all members' total capital contributions to New Albany. The Extension Agreement further provided that in the event that Baseline's membership interest in New Albany was reduced in the manner set forth above due to its failure to pay all of the outstanding capital calls, New Albany, under the terms of the Redemption Agreement, must immediately thereafter redeem Baseline's interest in New Albany in exchange for the assignment to Baseline of an interest in all of New Albany's assets equal to Baseline's then reduced membership interest.

On March 16, 2007, Baseline paid to New Albany $300,000 of the outstanding capital calls owed to New Albany, leaving an unpaid capital call balance of $1,921,000. Immediately thereafter, in accordance with the terms of the Extension Agreement and Section 3.3.(a) of New Albany's limited liability company agreement, Baseline's membership interest in New Albany was reduced from 50.0% to 40.42%. Baseline and New Albany then entered into a redemption agreement providing that Baseline's membership interest in New Albany was redeemed in exchange for an assignment by New Albany to Baseline of a 40.42% interest in all of New Albany's assets, including its oil and gas leasehold interests. The value of the redemption was approximately $8.0 million. On March 16, 2007, pursuant to Section 3.3(a) of New Albany's limited liability company agreement, Rex II elected to pay $3,157,000 to New Albany in satisfaction of its outstanding capital calls, as well as the unpaid outstanding capital calls of Baseline, Rex Energy Wabash, LLC, Shaner & Hulburt Capital Partners Limited Partnership and Lance T. Shaner. In accordance with Section 3.3(a) of New Albany's limited liability company agreement, the membership interests of the members were thereafter adjusted to reflect the additional capital contributions made by Rex II on behalf of Baseline, Rex Energy Wabash, LLC, Shaner & Hulburt Capital Partners Limited Partnership and Lance T. Shaner, and the redemption of Baseline's 40.42% membership interest. Following such adjustments, Rex II's membership interest in New Albany was increased from 26.833% to 45.04%, Rex Energy Wabash, LLC's membership interest was increased from 0.78% to 1.31%, Lance T. Shaner's membership interest was increased from 17.93% to 30.09%, Shaner & Hulburt Capital Partners Limited Partner's membership interest was increased from 2.94% to 4.93% and Douglas Oil & Gas's membership interest was increased from 11.10% to 18.63%.

On October 17, 2005, PennTex Resources redeemed the 40.0% limited partnership interest of Thomas J. Taylor in PennTex Resources. The redemption price was paid, in part, in the form of a distribution to Mr. Taylor of all of the Company's oil and gas producing properties in the states of Texas, Oklahoma, New Mexico, Arkansas, and Louisiana. The distribution of producing properties did not include PennTex Resources' jointly-owned oil producing properties located in the states of Illinois and Indiana.

The value of the partnership redemption was $11,425,000. Of this amount, $7,667,000 was distributed to Thomas J. Taylor in the form of cash. A distribution of net book value of property in the amount of $3,759,000 was also made. The cash distribution was financed by a personal loan to the Company from Lance T. Shaner. This loan had no term, no interest rate, and no interest was paid. The loan was repaid in January of 2006 with the proceeds of the PennTex M&T credit facility described in Note 8: *Long-Term Debt*.

5. CONCENTRATIONS OF CREDIT RISK

At times during the year ended December 31, 2007, our cash balance may have exceeded the Federal Deposit Insurance Corporation's limit of $100,000. There were no losses incurred due to such concentrations.

By using derivative instruments to hedge exposure to changes in commodity prices, we are exposed to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of the derivative is positive, the counterparty owes the Company, which creates repayment risk. We minimize the credit or repayment risk in derivative instruments by entering into transactions with high-quality counterparties.

6. COMMITMENTS AND CONTINGENCIES

Legal Reserves

At December 31, 2007, our Consolidated Balance Sheet included approximately $384,000 in reserve for the legal matters referenced in Note 19. At December 31, 2006, our Consolidated Balance Sheet included $891,000 in reserve for various legal proceedings. The accrual of reserves for legal matters is included in Accrued Expenses on the Consolidated Balance Sheet. The establishment of a reserve involves an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible that we could incur additional loss, the amount of which is not currently estimable, in excess of the amounts currently accrued with respect to those matters in which reserves have been established. Future changes in the facts and circumstances could result in actual liability exceeding the estimated ranges of loss and the amounts accrued. Based on currently available information, we believe that it is remote that future costs related to known contingent liability exposures for legal proceedings will exceed current accruals by an amount that would have a material adverse effect on our consolidated financial position or results of operations, although cash flow could be significantly impacted in the reporting periods in which such costs are incurred.

Drilling and Development

At December 31, 2007, we have two drilling commitments on certain leases in the Appalachian Basin. The first commitment requires we drill two natural gas wells by the end of 2008 in which we will be a 100% working interest owner. We estimate the total cost of the two wells to be approximately $1,700,000. The second drilling commitment is for us to drill two natural gas wells each year for the next five years, beginning in 2008. We estimate an average investment in each well to be $850,000 for a total five year drilling commitment of $8,500,000.

Environmental

Due to the nature of the natural gas and oil business, we are exposed to possible environmental risks. We have implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. We conducts periodic reviews to identify changes in the environmental risk profile. These reviews evaluate whether there is a probable liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any remediation effort.

We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Except for contingent liabilities associated with the enforcement action initiated by the U.S. EPA and the putative class action litigation filed in the U.S. District Court of the Southern District of Illinois relating to alleged H_2S emissions in the Lawrence Field, we know of no significant probable or possible environmental contingent liabilities.

Contract Wells

In March 2004, we purchased from Standard Steel, LLC certain contractual rights associated with various gas purchase contracts relating to 19 natural gas wells. Under the terms of the contracts we buy 100.0% of production from these wells from third parties at contracted, fixed prices. The prices we pay may range from $1.10 per Mcf to 55.0% of the market price, plus a $0.10 per Mcf surcharge. There is no loss on these commitments. We have recorded the gross revenue and costs in the Combined Statements of Operations. We sell the natural gas extracted from these contract wells to parties unrelated to these natural gas wells and contracts.

Letters of Credit

We have posted $938,000, at December 31, 2007, in various letters of credit to secure our drilling and related operations.

Lease Commitments

At December 31, 2007 we have lease commitments for three different office locations. Rent expense has been recorded in general and administrative expense as $192,000, $167,000 and $140,000 for the years ended 2007, 2006, and 2005, respectively. Lease commitments by year for each of the next five years are presented in the table below ($ in thousands).

2008	$ 354
2009	418
2010	355
2011	355
2012	355
Thereafter	436
Total	$2,273

Other

In addition to the Asset Retirement Obligation discussed in Note 2, we have withheld from distributions to certain other working interest owners amounts to be applied towards their share of those retirement costs. Such amounts totaling $322,000 are included in Other Liabilities at December 31, 2007 and December 31, 2006.

7. RELATED PARTY TRANSACTIONS

We lease an office building consisting of approximately 5,270 square feet of office space from Shaner Brothers, LLC, a Pennsylvania limited liability company (“Shaner Brothers”), which is owned by Mr. Shaner and Shaner Family Partners Limited Partnership, a Pennsylvania limited partnership controlled by Mr. Shaner. This office space, which we currently use as our headquarters, is located at 1975 Waddle Road, State College, Pennsylvania. We currently lease this office space pursuant to a written lease agreement between Rex Operating and Shaner Brothers effective as of September 1, 2006. The lease agreement provides for an initial term of three years and expires on August 31, 2009. The lease agreement requires the payment of rent in the amount of $7,908 per month, subject to adjustment on each anniversary date of the lease in accordance with the percentage of

increase in the Consumer Price Index for the U.S. for Urban Consumers (CPI-U) for the preceding year (the "CPI Adjustment"). The monthly rent is also subject to adjustment in the form of additional monthly rent which is calculated annually and equal to the percentage of increase of Shaner Brothers' costs for taxes, insurance premiums and operating expenses for the previous year (the "Additional Monthly Rent"). The annual monthly rent adjustment resulting from the CPI Adjustment and Additional Monthly Rent may not in the aggregate exceed a three percent increase over the prior lease year. Under the terms of the lease, we are responsible for certain costs relating to the interior construction of the building and the payment of all utilities, cleaning expenses, maintenance and other related costs and expenses of the building resulting from our operation, use and occupancy of the premises. Following the expiration of the initial term, we may renew the lease for up to three one-year extensions upon written notice to Shaner Brothers at least 120 days, but no more than six months, prior to the expiration of the current term. We believe the terms of this lease are comparable to terms that could be obtained at an arms' length basis in the State College, Pennsylvania area for leases of similar office space.

On December 26, 2007, we entered into a new office lease agreement with an unrelated third party to lease approximately 16,000 square feet of office space to serve as our new headquarters in State College, Pennsylvania. We expect to occupy our new office space in May 2008. Shaner Brothers is searching for a new tenant to lease our current office space; however, as of December 31, 2007, Shaner Brothers had not entered into a new lease agreement with any party. Under our current lease agreement with Shaner Brothers, we will be required to continue to pay all amounts owing under the lease agreement until expiration of its term or until such time as Shaner Brothers agrees to terminate the lease and rent the office space to another party. When the office space is leased by another party, we believe that Shaner Brothers will agree to terminate our current office lease agreement and release us from any further obligations under the agreement.

On September 1, 2006, Shaner Brothers loaned $264,656 to Rex Operating to fund its expenses relating to the construction of the interior portions of its headquarters office building. This loan was evidenced by an unsecured promissory note dated September 1, 2006. The promissory note provided for the payment of interest on the unpaid principal sum at a rate of 7% per annum. The loan was required to be repaid in 60 consecutive equal monthly installments of principal and interest in the amount of $5,240.50. The promissory note matured on September 1, 2011, but could be prepaid in whole or in part at anytime, without premium or penalty. We repaid this loan in its entirety on July 30, 2007 with proceeds from our initial public offering.

Prior to April 2007, we received certain administrative services (such as information technology, human resources, benefit plan administration, payroll and tax services) from Shaner Solutions Limited Partnership, a Delaware limited partnership controlled by Mr. Shaner ("Shaner Solutions"), pursuant to an oral month-to-month agreement providing for a monthly fee of $15,000, plus reimbursement for reasonable out-of-pocket expenses. On April 10, 2007, we terminated our oral month-to-month administrative services agreement with Shaner Solutions. For the period covering January 1, 2007 to April 10, 2007 we paid Shaner Solutions $53,000 in relation to these services. For the years ended December 31, 2006 and 2005, we paid $180,000 and $195,000, respectively, to Shaner Solutions in relation to these services. We believe that the amounts charged by Shaner Solutions were comparable to rates obtainable at an arm's-length basis in the State College, Pennsylvania area for similar services.

In conjunction with the termination of our oral agreement with Shaner Solutions, we entered into an IT Consultation and Support Services Agreement, a Service Provider Agreement and a Tax Return Engagement Letter Agreement with Shaner Hotel Group Limited Partnership, a Delaware limited partnership controlled by Lance T. Shaner ("Shaner Hotel"). Pursuant to the IT Consultation and Support Services Agreement, Shaner Hotel agreed to provide us with telecommunication, computer system and network administration, and information technology consultation services. Fees for the services provided under this agreement range from $55.00 to $125.00 per hour based upon the type and level of service provided, plus reimbursement for reasonable out-of-pocket expenses. The agreement continues until it is terminated by either party upon 90 days advance written notice. Pursuant to the Service Provider Agreement, Shaner Hotel agreed to provide us with certain clerical and administrative support services in connection with the management and administration of our 401(k)

retirement plan, payroll and employee health and welfare benefit plans. Under the agreement, we pay a fee of $95.00 per hour for any services performed by Shaner Hotel's benefits manager and a fee of $55.00 per hour for services provided by other members of Shaner Hotel's benefits department, plus reimbursement for reasonable out-of-pocket expenses. The term of the Service Provider Agreement is one year, however, either party may terminate the agreement upon 90 days advance written notice. Pursuant to the Tax Return Engagement Letter Agreement, Shaner Hotel agreed to provide us with certain tax planning and tax return preparation services. Fees for the services provided under this agreement range from $100.00 to $155.00 per hour based upon the tax expertise of the particular service provider, plus reimbursement for reasonable out-of-pocket expenses. The agreement continues until it is terminated by either party upon 90 days advance written notice. For the period covering April 10, 2007 to December 31, 2007, we paid $66,000 to Shaner Hotels in relation to these services. We believe that the amounts charged by Shaner Hotel are comparable to rates obtainable at an arm's-length basis in the State College, Pennsylvania area for similar services.

We currently have an oral month-to-month agreement with Charlie Brown Air Corp., a New York corporation owned by Mr. Shaner ("Charlie Brown"), regarding the use of two airplanes owned by Charlie Brown. Under our agreement with Charlie Brown, we pay a monthly fee for the right to use the airplanes equal to our percentage (based upon the total number of hours of use of the airplanes by us) of the monthly fixed costs for the airplanes, plus a variable per hour flight rate of $1,350 per hour. The total monthly fixed costs for the airplane is currently approximately $26,000 per month. For the year ended December 31, 2007 we paid Charlie Brown $188,000 in relation to these services. We believe the terms of this agreement are comparable to terms that could be obtained at an arms' length basis in the State College, Pennsylvania area for similar private aircraft services.

On June 21, 2007, we obtained a 24.75% limited partnership interest in Charlie Brown II Limited Partnership, a Delaware limited partnership ("Charlie Brown II"), and a 25% membership interest in its general partner, L&B Air LLC, a Delaware limited liability company ("L&B Air"). Charlie Brown II has ordered and agreed to purchase an Eclipse 500 Airplane for approximately $1,700,000. The airplane was scheduled to be delivered from the manufacturer to Charlie Brown II in January of 2008, but delivery of the airplane was delayed until June 2008. Shaner Hotel Group Limited Partnership, a Delaware limited partnership controlled by Mr. Shaner ("Shaner Hotel Group"), owns a 24.65% limited partnership interest in Charlie Brown II and a 25% membership interest in L&B Air, and Charlie Brown, an entity owned and controlled by Mr. Shaner, owns a .1% membership interest in Charlie Brown II. The remaining 49.50% limited partnership interest in Charlie Brown II and 50% interest in L&B Air is owned by an unrelated third party. On June 21, 2007, we made capital contributions to Charlie Brown II and L&B Air in the amount of $49,500 and $500, respectively. To fund these capital contributions, we borrowed $50,000 from our Chairman, Lance T. Shaner. This loan was evidenced by a promissory note dated June 21, 2007 and bore interest at the rate of 7% per annum. The promissory note was payable upon the demand of Mr. Shaner and could be prepaid in whole or in part without penalty. We believe that the terms of this loan were comparable to terms that could be obtained at an arms' length basis from unrelated lenders. We repaid this loan in its entirety on July 30, 2007 with proceeds from our initial public offering.

On June 21, 2007, Charlie Brown II and Charlie Brown entered into a First Amended and Restated Aircraft Joint Ownership and Management Agreement. Pursuant to this agreement, Charlie Brown agreed to provide certain aircraft management services, such as routine and scheduled maintenance, flight crew training, cleaning, inspections and flight operations and scheduling of the aircraft. In addition, Charlie Brown agreed to provide a flight crew for the operating of the aircraft and storage space in its hanger for storage of the aircraft. In exchange for these services, Charlie Brown II agreed to pay its proportionate share of Charlie Brown's fixed costs, including crew, hanger and insurance costs, and a per hour flight charge to be determined by Charlie Brown consistent with current local market rates charged by similar flight operation companies.

The business affairs of Charlie Brown II are managed by its general partner, L&B Air. L&B Air is managed by three managers, appointed by each of its three members. We have designated Benjamin W. Hulburt, our Chief Executive Officer, as the manager representing our membership interest. Actions of L&B Air must be approved

by a majority of the interest percentages of the managers. Each manager votes in matters before the company in accordance with the membership interest percentage of the member that appointed the manager. Certain events, such as the sale by a member of its interest, the merger or consolidation of L&B Air or Charlie Brown II, the filing of bankruptcy, or the sale of the airplane owned by Charlie Brown II, require the consent of all managers. The consent of all limited partners of Charlie Brown II is required before the partnership may change or terminate the management agreement with Charlie Brown, incur any indebtedness, sell substantially all of the partnership's assets or sell the airplane owned by the partnership. In the event that the limited partners are unable to unanimously agree upon any of these matters within 10 days of the proposal of any such matter, an "impasse" may be declared, and the airplane will be sold by the partnership.

On June 21, 2007, Charlie Brown II borrowed $1,530,000 from Graystone Bank. Proceeds from this loan were used to reimburse Lance T. Shaner and an unrelated third party for a deposit they paid on behalf of Charlie Brown II in connection with the purchase of the Eclipse 500 airplane. The loan matures on June 21, 2017 and bears interest at a rate of LIBOR plus 2.5%. The loan requires payments of interest only for the first three months of the loan. Thereafter, Charlie Brown II is required to make monthly payments of principal and interest utilizing an amortization period of 180 months. The loan to Charlie Brown II was guaranteed by Lance T. Shaner and the unrelated third party.

Mr. Shaner is our Chairman and a significant stockholder of the Company. Mr. Shaner's ownership and association with Shaner Brothers, Shaner Solutions, Shaner Hotel, Charlie Brown, Charlie Brown II and us could create a conflict of interest between the interests of those entities and Mr. Shaner's duties and obligations to us. The compensation for these arrangements and the purchase, leasing, financing, management and other arrangements between us and any Shaner affiliates may not be (to the extent permissible under applicable laws and regulations) a result of arm's-length negotiations, and the relationships created by virtue of these arrangements may be subject to certain conflicts of interest. Our board of directors (with Mr. Shaner abstaining) performs a quarterly review of these contractual agreements, whether oral or written, and may continue, extend, amend or terminate any of these agreements.

At December 31, 2006, there was a working capital loan payable to Mr. Shaner, our Chairman, in the amount of $1,820,000 from PennTex Illinois, one of the Predecessor Companies. At the time this loan was made, Mr. Shaner was the sole stockholder of PennTex Illinois. The loan was non-interest-bearing and was payable upon the demand of Mr. Shaner. In January 2007, the outstanding amount was satisfied through the conversion of $820,000 into an equity capital contribution into such Predecessor Company and the repayment of $1,000,000 to Mr. Shaner.

PennTex Resources repaid an outstanding debt to Lance T. Shaner in the amount of $8,136,000 during the year ended December 31, 2006.

During 2005, PennTex Illinois obtained two working capital loans from two related parties for a total of $1,400,000. The loans incurred interest at a rate of 13.0%. The total interest expense associated with the loans was $118,000. There was no outstanding balance on either loan at December 31, 2005.

At December 31, 2005, there was an accrued distribution owed to Lance T. Shaner in the amount of $3,100,000 which was paid in January of 2006.

At December 31, 2005, there was a receivable due from Lance T. Shaner in the amount of $700,000 with no term or due date. This amount was repaid in January 2006.

As of December 31, 2005, $139,500 of capital contributions receivable were due from related parties. The outstanding capital contributions were paid during 2006.

At December 31, 2005, there was an accrued distribution owed to Shaner & Hulburt Capital Partners in the amount of $30,000 which was paid in January 2006.

8. LONG-TERM DEBT

On January 19, 2006, PennTex Illinois and PennTex Resources, as co-borrowers, entered into a revolving line of credit of up to $22,500,000 with Manufacturers and Traders Trust Company, as agent (the "PennTex M&T Credit Facility"). The Borrowing Base for the PennTex M&T Credit Facility was $18,500,000 as of December 31, 2006. Interest on the credit facility accrued and was payable at a rate per annum equal to the base rate from time to time in effect, plus one percent (1.0%). We repaid the loan in full on July 31, 2007 from the proceeds of our initial public offering and closed the credit facility.

On February 13, 2006, Douglas Oil & Gas and Douglas Westmoreland, as co-borrowers, entered into a revolving line of credit of up to $10,000,000 with Manufacturers and Traders Trust Company, as agent (the "Douglas M&T Loan"). The Borrowing Base for the Douglas M&T Loan as of December 31, 2006 was $9,500,000. Interest on the loan accrued and was payable at a rate per annum equal to the base rate from time to time in effect, plus one percent (1.0%). The base rate was equal to the rate of interest per annum then most recently established by M&T Bank as its "prime rate", which rate may not be the lowest rate of interest charged by M&T Bank to its borrowers. We repaid the loan in full on July 31, 2007 from the proceeds of our initial public offering and closed the $10,000,000 revolving line of credit with M&T Bank.

On March 24, 2006, Rex II entered into a revolving line of credit for up to $3,700,000 with Sovereign Bank. Interest on the loan accrued and was equal to the rate of interest per annum from time to time established by Sovereign Bank as its prime rate of interest. On February 13, 2007, Rex II entered into an Amended and Restated Credit Agreement dated as of February 13, 2007 with Sovereign Bank, as Administrative Agent and Lead Arranger on behalf of signatory lenders which are parties to the agreement from time to time. At the closing of this loan transaction, the outstanding balance under Rex II's revolving line of credit with Sovereign Bank of $3,592,000 was refinanced and became an outstanding obligation under a new credit facility. The new credit facility provides for loans and letters of credit of up to a maximum of $11,500,000. We repaid the loan in full on July 31, 2007 from the proceeds of our initial public offering and closed the credit facility.

On June 28, 2006, Rex III entered into a Credit Agreement with Manufacturers and Traders Trust Company ("M&T Bank"), as Letter of Credit Issuer, Lead Arranger and Agent on behalf of signatory lenders which are parties to the agreement from time to time. The credit facility established under the Credit Agreement provides for loans and letters of credit of up to a maximum of $20,000,000. The Credit Agreement initially provided for a revolving credit loan up to a maximum of $15,000,000 and for term loans in the amount of up to $5,000,000. These terms were amended in July 2007 to increase the maximum on the line of credit to $15,625,000 and reduce the term loan maximum to $4,375,000. Interest on each advance under the revolving credit loan and the term loans accrues and is payable at a rate per annum selected by Rex III at either a LIBOR based rate or the applicable floating rate. We repaid the loans in full on July 31, 2007 from the proceeds of our initial public offering and closed the $15,625,000 revolving credit loan and $4,375,000 term loan with M&T Bank.

Rex IV entered into a Credit Agreement dated as of October 2, 2006 with KeyBank National Association ("KeyBank"), as Administrative Agent on behalf of signatory lenders which are parties to the agreement from time to time. The credit facility established under the Credit Agreement provides for loans and letters of credit of up to a maximum of $40,000,000. On October 1, 2006, Rex IV borrowed $36,581,000 under the new credit facility to pay the purchase price for the acquisition of certain oil properties from Tsar Energy II, LLC.

On March 30, 2007, Rex IV and KeyBank executed a First Amendment to the Credit Agreement which extended the maturity date of borrowings under the credit agreement to the earlier of (i) the date of closing of the Company's initial public offering or (ii) December 31, 2007. In addition, the First Amendment provided for a change in the interest rate per annum for Eurodollar borrowings to the LIBO rate plus 400 basis points. The First Amendment to the Credit Agreement also provided for revisions to certain negative covenants contained in the credit agreement. The ratio of total debt to EBITDAX was changed from 5.75:1.00 to 7.00:1.00 for the fiscal quarter ending June 30, 2007, 6.75:1.00 for the fiscal quarter ending September 30, 2007 and 6.50:1.00 for the

fiscal quarter ending December 31, 2007. The First Amendment also provided that for the purposes of calculating both ratios, EBITDAX excludes non-reoccurring legal expenses of Rex IV.

On July 24, 2007, Rex IV and KeyBank executed a Second Amendment to the Credit Agreement, which extended the maturity date of the credit agreement to the earlier to occur of (a) the closing date of a new senior credit facility of the Company or (b) December 31, 2007. On July 31, 2007, we made a payment of approximately $27.8 million on this line of credit.

On July 31, 2007, we used the proceeds from the initial public offering to repay all credit facilities of the Predecessor Companies with the exception of the Rex IV line of credit. A payment of approximately $27.8 million on the Rex IV line of credit was made resulting in remaining indebtedness on the line of approximately $14.6 million as of July 30, 2007. The remaining balance on the Rex IV line of credit was subsequently repaid with borrowings from our new senior-secured line of credit.

On September 28, 2007, we entered into a new credit agreement with KeyBank National Association ("KeyBank"), as Administrative Agent, BNP Paribas, as Syndication Agent, Sovereign Bank, as Documentation Agent, and lenders from time to time parties thereto (the "New Credit Agreement"). Borrowings under the New Credit Agreement are limited by a borrowing base that is determined in regard to our oil and gas properties. The borrowing base is $75 million; however, the New Credit Agreement provides that the revolving credit facility may be increased up to $200 million upon re-determinations of the borrowing base, consent of the lenders and other conditions prescribed in the agreement. Within that borrowing base, outstanding letters of credit are permitted up to $10 million. Loans made under the New Credit Agreement mature on September 28, 2012, and in certain circumstances, we will be required to prepay the loans. At our election, borrowings under the New Credit Agreement bear interest at a rate per annum equal to (a) the London Interbank Offered Rate for one, two, three, six or nine months ("Adjusted Libor Rate") plus an applicable margin ranging from 100 to 175 basis points plus a commitment fee ranging from 25 to 37.5 basis points or (b) the higher of KeyBank's announced prime rate ("Prime Rate") and the federal funds effective rate from time to time plus 0.5%, in each case, plus an applicable margin ranging from 0 to 25 basis points plus a commitment fee ranging from 25 to 37.5 basis points. Interest is payable on the last day of each relevant interest period in the case of loans bearing interest at the Adjusted Libor Rate and quarterly in the case of loans bearing interest at the Prime Rate. The average interest rate on our New Credit Agreement at December 31, 2007 was approximately 6.8%, before the effect of interest rate hedging. The New Credit Agreement provides that the borrowing base will be re-determined semi-annually by the lenders, in good faith, based on, among other things, reports regarding our oil and gas reserves attributable to our oil and gas properties, together with a projection of related production and future net income, taxes, operating expenses and capital expenditures. On or before March 1 and September 1 of each year, we are required to furnish to the lenders a reserve report evaluating our oil and gas properties as of the immediately preceding January 1 and July 1. The reserve report as of January 1 of each year must be prepared by one or more independent petroleum engineers approved by the Administrative Agent. Any re-determined borrowing base will become effective on the subsequent April 1 and October 1. We may, or the Administrative Agent at the direction of a majority of the lenders may, each elect once per calendar year to cause the borrowing base to be re-determined between the scheduled re-determinations. In addition, we may request interim borrowing base re-determinations upon our proposed acquisition of proved developed producing oil and gas reserves with a purchase price for such reserves greater than 10% of the then borrowing base.

The New Credit Agreement contains covenants that restricts our ability to, among other things, materially change our business, approve and distribute dividends, enter into transactions with affiliates, create or acquire additional subsidiaries, incur indebtedness, sell assets, make loans to others, make investments, enter into mergers, incur liens, and enter into agreements regarding swap and other derivative transactions. The New Credit Agreement also requires we meet, on a quarterly basis, minimum financial requirements of consolidated current ratio, EBITDAX to interest expense and total debt to EBITDAX. Proceeds of the initial borrowing under the New Credit Agreement were used to repay, in full, and terminate the existing credit agreement of Rex Energy IV, LLC, our wholly owned subsidiary. Subsequent borrowings under the New Credit Agreement have been used to

finance our working capital needs, and for general corporate purposes in the ordinary course of business, including the exploration, acquisition and development of oil and gas properties. Obligations under the New Credit Agreement are secured by mortgages on the oil and gas properties of our subsidiaries located in the states of Illinois and Indiana. We are required to maintain liens covering our oil and gas properties representing at least 80% of our total value of all oil and gas properties.

At December 31, 2007, we had a balance of approximately $27.2 million on the New Credit Agreement and had approximately $47.8 million available for future borrowings under the facility.

Rex IV had previously maintained a line of credit facility that had been paid in full and closed during the period ended September 30, 2007. This credit facility had a maturity date of less than one year and is categorized as a current liability on the combined balance sheet as of December 31, 2006. All long-term debt, loans and notes payable held by the Predecessor Companies, in addition to the Rex IV line of credit, were paid in full and the credit facilities closed during the three month period ended September 30, 2007.

In addition to our New Credit Agreement, we may, from time to time in the normal course of business, finance assets such as vehicles, office equipment and leasehold improvements through debt financing at favorable terms. Long-term debt and lines of credit consists of the following at December 31, 2007 and 2006:

	December 31, 2007 ($ in Thousands)	December 31, 2006 ($ in Thousands)
Douglas M&T Loan	$ 0	$ 8,941
PennTex M&T Credit Facility	0	14,944
Rex II Credit Facility	0	3,550
Rex III Credit Agreement	0	20,000
Line of Credit—Rex IV	0	37,581
Senior-Secured Lines of Credit	27,186	0
Other Loans and Notes Payable	50	874
Total Debts	27,236	85,890
Less Current Portion of Long-Term Debt	(29)	(40,448)
Total Long-Term Debts	$27,207	$ 45,442

The terms of the New Credit Agreement require we make monthly payment of interest on the outstanding balance of loans made under the agreement. Loans made under the New Credit Agreement mature on September 28, 2012, and in certain circumstances, we will be required to prepay the loans.

The following is the principal maturity schedule for debt outstanding as of December 31, 2007 ($ in thousands):

	Year Ended December 31,
2008	$ 29
2009	21
2010	—
2011	—
2012	27,186
Thereafter	—
Total	$27,236

9. FAIR VALUE OF FINANCIAL INSTRUMENTS AND DERIVATIVE INSTRUMENTS

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of Statement of Financial Accounting Standard No. 107, "*Disclosures About Fair Value of Financial Instruments*." We have determined the estimated fair value amounts by using available market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

Financial instruments include cash and cash equivalents, receivables, payables, commodity and interest rate derivatives. The carrying value of items comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. The carrying value of our long-term debt instruments approximates the fair value as the debt facilities carry a market rate of interest.

We estimate the fair value of the participation liability associated with a prior term loan to be $2,141,000 as of December 31, 2006. The participation liability was paid in full and extinguished on July 31, 2007 for $2,141,000.

The fair value of the net liability associated with our derivative instruments was approximately $29,715,000 and $3,258,000 at December 31, 2007 and 2006, respectively. The fair value is based on valuation methodologies of our counterparties. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we entered into oil and natural gas commodity derivative instruments. As of December 31, 2007 and December 31, 2006, our oil and natural gas derivative commodity instruments consisted of fixed rate swap contracts and collars. These instruments do not qualify as cash flow hedges for accounting purposes. Accordingly, associated unrealized gains and losses are recorded directly as other income or expense.

Swap contracts provide a fixed price for a notional amount of sales volumes. Collars contain a fixed floor price (put) and ceiling price (call). The put options are purchased from the counterparty by our payment of a cash premium. If the put strike price is greater than the market price for a calculation period, then the counterparty pays us an amount equal to the product of the notional quantity multiplied by the excess of the strike price over the market price. The call options are sold to the counterparty for which we receive a cash premium. If the market price is greater than the call strike price for a calculation period, then we pay the counterparty an amount equal to the product of the notional quantity multiplied by the excess of the market price over the strike price.

We enter into the majority of our derivatives transactions with two counterparties and have a netting agreement in place with each of these counterparties. We do not obtain collateral to support the agreements but monitor the financial viability of counterparties and believe our credit risk is minimal on these transactions.

We sell oil and natural gas in the normal course of business and utilizes derivative commodity instruments to minimize the variability in forecasted cash flows due to price movements in oil and natural gas sales.

We incurred net payments of $6,198,000 and $4,436,000 under these commodity derivative instruments during years ended December 31, 2007 and 2006, respectively. These net payments are included in operating revenue on our consolidated and combined statement of operations. Unrealized gains (losses) associated with these derivative instruments are included in other income (expense) and amounted to ($26,250,000) and $5,043,000 for the years ended December 31, 2007 and 2006, respectively.

Our open asset/ (liability) financial commodity derivative instrument positions at December 31, 2007 consisted of:

Period	Contract Type	Volume	Average Derivative Price	Fair Market Value ($ in Thousands)
Oil				
2008	Swaps	204,000 Bbls	$65.58	$ (5,489)
2008	Collars	369,000 Bbls	$62.33 – 80.26	$ (5,374)
2009	Swaps	192,000 Bbls	$64.00	$ (4,334)
2009	Collars	350,000 Bbls	$62.30 – 67.95	$ (6,930)
2010	Swaps	180,000 Bbls	$62.20	$ (3,842)
2010	Collars	288,000 Bbls	$60.00 – 78.25	$ (3,210)
	Total	1,583,000 Bbls		$(29,179)
Natural gas				
2008	Collars	840,000 Mcf	$ 7.00 – 9.19	$ (9)
2009	Collars	600,000 Mcf	$ 7.00 – 9.00	$ (320)
	Total	1,440,000 Mcf		$ (329)

As of December 31, 2007 we had entered into an interest rate swap derivative instrument in which we effectively hedged our interest rate risk associated with changes in LIBOR on $20,000,000 of notional value. We use the interest rate swap agreement to manage the risk that interest payments on amounts outstanding under the variable rate bank credit facility may be adversely affected by volatility in market interest rates. Under our interest rate swap agreement, we agree to pay an amount equal to a specified fixed rate of interest times a notional principal amount, and to receive in return, a specified variable rate of interest times the same notional principal amount. At December 31, 2007, we had interest rate swap agreements totaling $20.0 million. The swaps consists of an agreement at 4.15% which expires in November 2010. The fair value of the swap at December 31, 2007, was a liability of $207,000 based on current LIBOR quotes. On December 31, 2007, the 30-day LIBOR rate was 4.6%. The critical terms of this interest rate swap and our credit facility closely coincide and there was no ineffectiveness at December 31, 2007. The swap is considered to be a highly effective hedge against future changes in interest rates. We have accounted for the hedge in accordance with SFAS No. 133 by recording the $207,000 unrealized loss at December 31, 2007 on an after tax basis as a decrease to other comprehensive income of $123,000 and an increase in deferred tax assets of $84,000 on our consolidated balance sheet.

10. INCOME TAXES

We account for income taxes in accordance with the provisions of Statement of Financial Accounting Standards ("SFAS") No. 109, *"Accounting for Income Taxes"*. This statement requires a company to recognize deferred tax liabilities and assets for the expected future tax consequences of events that may be recognized in our financial statements or tax returns. Using this method, deferred tax liabilities and assets are determined based on the difference between the financial carrying amounts and tax bases of assets and liabilities using enacted tax rates. We recognized deferred tax assets and liabilities upon the consummation of the Reorganization Transactions and acquisition of minority interests. Before these events, the Predecessor Companies were pass-through entities that did not pay income taxes and did not reflect deferred tax assets and liabilities.

Effective August 1, 2007, we adopted Financial Accounting Standards Board ("FASB") Interpretation No. 48, "*Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement No. 109*" ("FIN 48"), which clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with SFAS No. 109, *"Accounting for Income Taxes"*. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. We also adopted FASB Staff Position No. FIN 48-1, "*Definition of Settlement in FASB Interpretation No. 48"* ("FSP FIN 48-1") as of August 1, 2007. FSP FIN 48-1 provides that a

company's tax position will be considered settled if the taxing authority has completed its examination, the company does not plan to appeal, and it is remote that the taxing authority would reexamine the tax position in the future. The adoption of FIN 48 and FSP 48-1 had no effect on our financial position or results of operations.

The Predecessor Companies were treated as partnerships or subchapter S corporations for federal and state income tax purposes. Accordingly, income taxes were not reflected in the combined financial statements because the resulting profit or loss was included in the income tax returns of the individual stockholders, members or partners. Accordingly, we did not derecognize any tax benefits, nor recognize any interest expense or penalties on unrecognized tax benefits as of the date of adoption. Income tax expense has been provided for on our consolidated statement of operations prospectively for periods after August 1, 2007.

We will file a consolidated federal income tax return and separate or consolidated state income tax returns in the United States federal jurisdiction and in many state jurisdictions. We are subject to U.S. Federal income tax examinations and to various state tax examinations for periods after August 1, 2007. Our practice is to recognize interest related to income tax expense in interest expense and penalties in general and administrative expense. We do not have any accrued interest or penalties as of December 31, 2007.

Our deferred tax assets at December 31, 2007 include an estimated net operating loss carryforward of $4.5 million, which expires in 2027, for tax losses recognized during the five month period ended December 31, 2007. Income tax benefit for the five month period ended December 31, 2007 is comprised of the following ($ in thousands):

	Five Month Period Ended December 31, 2007
Current:	
Federal	$1,546
State	287
Deferred:	
Federal	4,457
State	727
Total Income Tax Benefit	$7,017

A reconciliation of income tax expense using the statutory U.S. income tax rate compared with actual income tax expense is as follows:

	Rex Energy Corporation Five months Ended December 31, 2007
	($ in Thousands)
Net loss before minority interests and income taxes	$(29,380)
Pre-tax loss Before reorganization not subject to federal income taxes	11,724
Net loss before income taxes	$(17,656)
Statutory U.S. income tax rate	34%
Tax benefit recognized using statutory U.S. income tax rate	$ 6,003
State income tax benefit	1,014
Income tax benefit	$ 7,017
Effective income tax rate	39.7%

Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes. Deferred tax liabilities/(assets) are comprised of the following at December 31, 2007. The combined Predecessor Companies at December 31, 2006 consisted of limited liability partnerships, limited liability companies, and subchapter S corporations whose taxable income (loss) passed to the various members, partners, and stockholders in those respective entities. Accordingly, no deferred tax liabilities or assets were recognized by those entities at December 31, 2006:

	Rex Energy Corporation December 31, 2007
	($ in Thousands)
Tax effects of temporary differences for:	
Current:	
Assets:	
Unrealized loss on derivatives	$ 4,350
Other	350
Total current deferred tax assets	4,700
Long-Term:	
Assets:	
Asset Retirement Obligation	2,580
Unrealized loss on derivatives	7,580
Net Operating Loss Carryforward	1,830
Other	1,110
Total long-term deferred tax assets	13,100
Liabilities:	
Book basis of oil and gas properties in excess of tax basis	(43,400)
Net long-term deferred tax liability	$(30,300)

11. CAPITAL STOCK

We have authorized capital stock of 100,000,000 shares of common stock and 100,000 shares of preferred stock. In July 2007 we completed our initial public offering of 9,600,000 shares of common stock at $11.00 per share. As of December 31, 2007, we had 30,784,720 shares of common stock outstanding.

12. MAJOR CUSTOMERS

PennTex Illinois, PennTex Resources, Rex I, LLC. and Rex IV sold 100.0% of their oil production in the Indiana and Illinois fields to Countrymark Cooperative LLP. The total amount of oil sold to Countrymark Cooperative, LLP in 2007, 2006, and 2005 was approximately $52.2 million, $27.7 million, and $18.1 million, respectively. These sales represent 82.4%, 63.5%, and 62.2%, respectively, of total oil and natural gas sales.

13. EMPLOYEE BENEFIT AND EQUITY PLANS

401(k) Plan

We sponsor a 401(k) Plan for eligible employees who have satisfied age and service requirements. Employees can make contributions to the plan up to allowable limits. Our contributions to the plan are discretionary. Our contributions to the plan were approximately $204,000, $185,000 and $109,000 for the years ended December 31, 2007, 2006 and 2005, respectively. We paid approximately $8,000, $8,000 and $4,000 of expenses on behalf of the 401(k) plan for the years ended December 31, 2007, 2006 and 2005, respectively.

2007 Long-Term Incentive Plan

We have granted stock option awards to various employees and non-employee directors under the terms of the 2007 Long-Term Incentive Plan (the "Plan"). The Plan is administration by our Compensation Committee. Among the Compensation Committee's responsibilities are selecting participants to receive awards, determining the form, amount and other terms and conditions of awards, interpreting the provisions of the Plan or any award agreement and adopting such rules, forms, instruments and guidelines for administering the Plan as it deems necessary or proper. All actions, interpretations and determinations by the Compensation Committee are final and binding. The composition of the Compensation Committee is intended to permit the awards under the Plan to qualify for exemption under Rule 16b-3 of the Exchange Act. In addition, awards under the Plan, including annual incentive awards paid to executive officers subject to section 162(m) of the Code, or covered employees, will satisfy the requirements of section 162(m) to permit the deduction by us of the associated expenses for Federal income tax purposes.

On November 6, 2007, the Compensation Committee awarded grants of 675,000 nonqualified stock options to 25 employees. The nonqualified stock options granted to our employees have an exercise price equal to $9.99, the closing price of our common stock on the NASDAQ Global Market on the date of the grant, and vest and become exercisable on the third anniversary of the grant date, provided that the option holder remains an employee of the company until that date. The options provide that all unvested options vest and become immediately exercisable upon a change in control of the company, as such term is defined in the Plan. On November 7, 2007, the Committee awarded an additional 150,000 nonqualified stock options to the four of our non-employee directors. The nonqualified stock options granted to our non-employee directors have an exercise price equal to $9.50, the closing price of our common stock on the NASDAQ Global Market on the date of the grant, and vest and become exercisable in one-third increments on the first, second and third anniversaries of grant date, provided that the director remains a member of our board of directors on each such anniversary date. The options provide that all unvested options vest and become immediately exercisable upon a change in control of the company, as such term is defined in the Plan, or in the event that the non-employee director is not re-nominated or re-elected to our board of directors or resigns from the board of directors as a direct result of a vote of our stockholders. At December 31, 2007, net of the forfeiture of 10,000 options, the remaining number of shares that may be issued under the plan equaled 2,264,470.

Stock options represent the right to purchase shares of stock in the future at the fair market value of the stock on the date of grant. All of the stock options granted under the Plan expire ten years from the date they are granted. In the event that any outstanding award expires, is forfeited, cancelled or otherwise terminated without the issuance of shares of our common stock or is otherwise settled in cash, shares of our common stock allocable to such award, including the unexercised portion of such award, shall again be available for the purposes of the Plan. If any award is exercised by tendering shares of our common stock to us, either as full or partial payment, in connection with the exercise of such award under the Plan or to satisfy our withholding obligation with respect to an award, only the number of shares of our common stock issued net of such shares tendered will be deemed delivered for purposes of determining the maximum number of shares of our common stock then available for delivery under the Plan.

All awards granted under the Plan have been issued at the prevailing market price at the time of the grant. All outstanding stock options have been awarded with a 10-year expiration at an exercise price equal to our closing price on the NASDAQ Global Market on the day of the award. Information with respect to these stock option activities is summarized below:

			Outstanding			Exercisable	
Range of Exercise Prices	Shares Granted	Shares Forfeited	Shares Outstanding	Weighted-Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
$9.51 – $10.00	675,000	10,000	665,000	9.83	9.99	0	0
$9.00 – $9.50	150,000	0	150,000	9.83	$9.50	0	0
Total			815,000	9.83	$9.90	0	0

The value of each option grant on the date of grant for the disclosures is estimated by using the Black-Scholes option pricing model with the following assumptions used for 2007 option grants of 675,000 shares and 150,000, respectively: fair value of $5.08 and $4.85 per share; expected dividend per share of $0.00; expected historical volatility factors of 44%; risk-free interest rates of 4.1%, and an average expected life of 6.5 years. Our expected historical volatility factor has been determined upon assessing the common stock trading history of 11 publicly-traded oil and gas companies which we determined to be similar to us in ways such as, their operating strategy, capital structure, production mix and volume, and asset size. The risk-free interest rate was determined by interpolating the average yield on a U.S. Treasury bond for a period approximately equal to the expected average life of the options. The average expected life has been determined using the "simplified method" as referenced in SEC Staff Accounting Bulletin 107 ("SAB 107") in which the average expected life of the option is equal to the average of the term of the option and the vesting period. We elected to use the simplified method for determining the average expected life because we do not have a reliable history on which to base estimates for future forfeiture rates and the early exercise of our granted stock options.

We estimate to expense approximately $3.8 million of compensation expense related to our stock options over the remaining vesting period of the options. Unless sooner terminated, our outstanding options as of December 31, 2007 will all be fully-vested by November 2010. There were no options exercised, proceeds received or associated income tax benefits realized during the year ended December 31, 2007.

14. SUSPENDED EXPLORATORY WELL COSTS

We follow FSP No. 19-1 "*Accounting for Suspended Well Costs*" ("FSP 19-1"), which permits the continued capitalization of exploratory well costs if a well finds a sufficient quantity of reserves to justify its completion as a producing well and we are making sufficient progress towards assessing the reserves and the economic and operating viability of the project. The following table reflects the net changes in capitalized exploratory well costs during the periods indicated, and includes amounts that were capitalized and subsequently expensed in the same period ($ in thousands).

The following table reflects the net change in capitalized exploratory well costs for the years ended December 31, 2007 and 2006 ($ in thousands):

	2007	2006
Beginning Balance at January 1	$ 2,538	$ 0
Additions to capitalized exploratory well costs pending the determination of proved reserves	6,921	2,574
Reclassification of wells, facilities, and equipment based on the determination of proved reserves	0	0
Capitalized exploratory well costs charged to expense	(2,948)	(36)
Ending Balance at December 31	6,511	2,538
Less exploratory well costs that have been capitalized for a period of one year or less	(5,072)	(2,538)
Capitalized exploratory well costs that have been capitalized for a period of greater than one year	$ 1,439	$ 0
Number of projects that have exploratory well costs capitalized for a period of more than one year	1	0

The $1.4 million in capitalized well costs that have been capitalized for a period of greater than one year were incurred in 2006. These costs all relate to our New Albany Shale natural gas exploration project in southern Indiana. We are undergoing an analysis of various stimulation techniques to determine if economic quantities of natural gas can be produced from this project.

The $2.9 million of capitalized exploratory well costs charged to expense resulted from two primary sources. A single well in our southwestern region was drilled and determined to be dry in early 2007 at a cost of approximately $1.7 million. Additionally, we evaluated three vertical-intercept wells that were drilled as part of the New Albany Shale natural gas exploration project and deemed those wells were not candidates for additional stimulation which resulted in the recognition of approximately $1.2 million of exploration expense.

15. COSTS INCURRED IN OIL AND NATURAL GAS ACQUISITION AND DEVELOPMENT ACTIVITIES

Costs incurred in oil and natural gas property acquisitions and development are presented below:

	2007	2006	2005
Oil and Natural Gas Property Acquisition Costs	$ 2,770	$70,159	$22,855
Undeveloped Acreage	—	1,116	246
Unproven Acreage	5,384	13,186	—
Capitalization of Exploratory Well Costs-Net	5,072	2,538	—
Exploration Expense of Oil and Natural Gas Properties	2,948	—	—
Development Costs	27,665	11,166	4,058
Total	$43,839	$98,165	$27,159

Property acquisition costs include costs incurred to purchase, lease, or otherwise acquire property as well as capitalized future abandonment costs. Development costs include costs incurred to gain access to and prepare development well locations for drilling, to drill and equip development wells, and to provide facilities to extract, treat, and gather natural gas and oil.

16. OIL AND NATURAL GAS CAPITALIZED COSTS

Our aggregate capitalized costs for natural gas and oil production activities with applicable accumulated depreciation, depletion and amortization is presented below. The capitalized costs in 2007 include a step-up in basis of approximately $70.5 million resulting from the Reorganization Transactions ($ in thousands).

	2007	2006
Proven Oil and Natural Gas Properties	$196,410	$127,354
Pipelines and Support Equipment	2,403	2,104
Field Operation Vehicles and Other Equipment	2,075	2,036
Wells and Other Work in Progress	10,773	2,861
Unproven Properties	33,881	14,569
Total	245,542	148,924
Less Accumulated Depreciation and Depletion	(33,412)	(17,589)
Total	$212,130	$131,335

17. OIL AND NATURAL GAS RESERVE QUANTITIES (UNAUDITED)

Our independent engineers, Netherland, Sewell, and Associates, Inc., have evaluated our proved oil and natural gas reserves for the years ended December 31, 2007 and 2006, We emphasize that reserve estimates are inherently imprecise. Our oil and natural gas reserve estimates were generally based upon extrapolation of historical production trends, analogy to similar properties, and volumetric calculations. Accordingly, these estimates are expected to change, and such change could be material and occur in the near term as future information becomes available. All of our proved reserves are located within the United States.

Proved oil and natural gas reserves represent the estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable accuracy will be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Reservoirs are considered proved if economic productibility is supported by either actual production or conclusive formation tests. The area of a reservoir considered proved includes (a) that portion delineated by drilling and defined by natural gas and oil and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. Reserves which can be produced economically through application of improved recovery techniques are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Proved developed oil and natural gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and natural gas expected to be obtained through the application of other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the installed program has confirmed through production responses that increased recovery will be achieved.

Presented below is a summary of changes in estimated reserves of the oil and natural gas wells at December 31, 2007 and 2006. The reserves are proved.

	2007		
	Oil (Bbls)	Natural Gas (Mcf)	Oil Equivalents
Proved Reserves—Beginning of period	11,594,022	17,212,857	14,462,832
Extensions and Discoveries	96,466	1,472,234	341,838
Purchases of Reserves in Place	84,374	—	84,374
Revisions of Previous Estimates	1,816,233	1,023,434	1,986,805
Production	(814,857)	(1,159,999)	(1,008,190)
Proved Reserves—End of Period	12,776,238	18,548,526	15,867,659

	2006		
	Oil (Bbls)	Natural Gas (Mcf)	Oil Equivalents
Proved Reserves—Beginning of period	6,378,064	16,094,829	9,060,536
Purchases of Reserves in Place	6,394,302	1,709,829	6,679,274
Extensions and Discoveries	0	1,184,960	197,493
Revisions of Previous Estimates	590,874	666,757	(702,085)
Production	587,470	1,109,494	(772,386)
Proved Reserves—End of Period	11,594,022	17,212,857	14,462,832
Proved Developed Reserves			
December 31, 2006	9,294,809	11,366,423	11,189,212
December 31, 2007	10,253,387	12,832,921	12,392,207

18. STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS (UNAUDITED)

Statement of Financial Accounting Standard No. 69, ("SFAS 69"), prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to the estimated proven reserves. We followed these guidelines, which are briefly discussed below.

Future cash inflows and future production and development costs are determined by applying year-end prices and costs to estimate quantities of oil and natural gas to be produced. Actual future prices and costs may

be materially higher or lower than the year-end prices and costs used. Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions. The resulting future net cash flows are reduced to present value amounts by applying a 10.0% annual discount factor.

The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates reflect the valuation process.

The following summary sets forth our future net cash flows relating to proved oil and natural gas reserves based on the standardized measure prescribed by SFAS 69 at December 31, 2007 and 2006 ($ in thousands):

	2007	2006
Future Cash Inflows	$1,294,564(a)	$ 750,017(b)
Future Costs:		
Production	(522,621)	(362,883)
Abandonment	(13,785)	(11,320)
Development	(49,694)	(34,701)
Net Future Cash Inflows Before Income Taxes	708,464	341,113
Future Income Tax Expense	(240,781)	—
Total Future Net Cash Flows Before 10% Discount	467,683	341,113
Less: Effect of a 10.0% Discount Factor	(212,724)	(146,134)
Standardized Measure of Discounted Future Net Cash Flows	$ 254,959	$ 194,979

(a) Calculated using weighted average prices of $6.79 per Mcf and $92.50 per barrel of oil
(b) Calculated using weighted average prices of $5.64 per Mcf and $57.75 per barrel of oil

The principal sources of change in the standardized measure of discounted future net cash flows are as follows:

	2007	2006
Standardized Measure—Beginning of Period	$ 194,979	$148,153
Revisions of Previous Estimates:		
Changes in Prices and Production Costs	179,813	(45,067)
Revisions in Quantities	54,703	(9,106)
Changes in Future Development Costs	(16,684)	(2,309)
Accretion of Discount and Timing of Future Cash Flows	19,498	14,810
Net Change in Income Tax	(130,721)	—
Purchases of Reserves in Place	1,405	105,906
Plus Extensions, Discoveries, and Other Additions	4,371	707
Development Costs Incurred	20,378	11,200
Sales of Product—Net of Production Costs	(39,048)	(25,040)
Changes in Timing and Other	(32,608)	(1,264)
Future Abandonment Costs	(1,127)	(3,011)
Standardized Measure—End of Period	$ 254,959	$194,979

19. LITIGATION

PennTex Resources—Wood Arbitration and Confirmation of Arbitration Award

PennTex Resources is involved in the confirmation of an award issued by an arbitration panel convened by the American Arbitration Association in Houston, Texas. This was a binding arbitration proceeding that was

commenced on June 21, 2006, by PennTex Resources and our Chairman, Lance T. Shaner ("Shaner"), against ERG Illinois Holdings, Inc. ("ERG Holdings") and its sole stockholder, Scott Y. Wood ("Wood"), pursuant to the dispute resolution provisions of a stock purchase agreement that was entered into in January 2005 by Wood's company, ERG Holdings, as "Seller," and PennTex Resources, as "Buyer" (the "2005 Stock Purchase Agreement"). The principal claim in the arbitration proceeding was PennTex Resources' and Shaner's claim that ERG Holdings and Wood should be ordered to comply with a "claim release obligation" contained in the 2005 Stock Purchase Agreement that requires Wood, under certain designated circumstances, to dismiss or release the individual claims that he was prosecuting against Tsar and Cheatham (the "Tsar Case"). PennTex Resources became obligated to file this arbitration proceeding seeking to enforce Wood's "claim release obligation" by reason of an agreement that PennTex Illinois and PennTex Resources entered into on March 2, 2006 with Tsar and Cheatham in order to resolve certain procedural issues relating to the Tsar Case.

PennTex Resources and/or Shaner also filed the following additional claims in the arbitration proceeding: (a) a claim against ERG Holdings seeking an award of $383,760, plus pre-award interest and attorneys' fees, based on ERG Holdings' alleged breach of its obligation to make an appropriate post-closing purchase price adjustment under the 2005 Stock Purchase Agreement; (b) a claim against ERG Holdings seeking an award of approximately $20,000, plus pre-award interest and attorneys' fees, based on ERG Holdings' alleged breach of a contractual obligation to return the original and all copies of a letter a credit posted by PennTex Resources to secure its indemnity obligations under the 2005 Stock Purchase Agreement, which breach was alleged to have wrongfully caused PennTex Resources to have had to unnecessarily incur an annual renewal fee to keep such letter of credit in force and (c) a claim against ERG Holdings seeking an award of approximately $23,500, plus pre-award interest and attorneys' fees, based on ERG Holdings' alleged breach of its obligation to make an appropriate pre-closing purchase price adjustment to reflect in its final closing statement an existing liability owed to the owners of a net profits interest relating to certain leases within the Lawrence Field.

On June 30, 2006, Wood filed suit against PennTex Resources and Shaner in the United States District Court for the Southern District of Texas seeking to obtain a declaratory judgment that Wood could not be compelled to participate in the arbitration proceeding on the grounds that he was not a signatory to the 2005 Stock Purchase Agreement. On August 1, 2006, PennTex Resources and Shaner responded to Wood's complaint by filing an answer and counterclaim asserting that the action should be stayed, and that Wood should be compelled to proceed to arbitration in the pending arbitration proceeding. On October 23, 2006, the court issued an order granting PennTex Resources' and Shaner's motion to compel arbitration. On November 2, 2006, in response to defendants' joint motion in support of stay, rather than dismissal, the court signed an order staying the action and administratively closing it pending the final award in the underlying arbitration proceeding.

On January 22, 2007, Wood and ERG Holdings filed a response in the arbitration proceeding disputing the standing of Shaner and PennTex Resources to participate in the arbitration and denying all claims made by the claimants. In addition, ERG Holding asserted a counterclaim against PennTex Resources for a post-closing adjustment in the purchase price under the 2005 Stock Purchase Agreement in its favor in the amount of $182,865. In February 2007, Wood brought a counterclaim against PennTex Resources in the amount of $171,351 for attorney's fees and expenses incurred by Wood in the Tsar Case alleging that PennTex Resources was required to reimburse Wood for such fees and expenses under the 2005 Stock Purchase Agreement. The arbitration panel of the American Arbitration Association held a final hearing in the arbitration proceeding on June 25 and 26, 2007. On June 25, 2007, at his request and without objection by Wood or ERG Holdings, the panel dismissed Shaner as a claimant in the arbitration. In addition, PennTex Resources withdrew its claim for the $23,500 pre-closing purchase price adjustment.

On August 20, 2007, the arbitration panel issued its findings and awards in the arbitration proceeding. The panel awarded Wood the amount of $92,540 for attorney's fees and expenses incurred by Wood relative to prosecuting his counterclaims in the Tsar Case. The panel found or awarded PennTex Resources the following: (a) with respect to its claim for post-closing purchase price adjustments under 2005 Stock Purchase Agreement, ERG Holdings was required to pay PennTex Resources $88,777, with interest at 6% per annum until paid,

(b) ERG Holdings and Wood were required to return the original and all copies of the $1,000,000 letter of credit previously provided by PennTex Resources pursuant to the 2005 Stock Purchase Agreement and ordered not to draw upon or attempt to draw upon the letter of credit conditioned upon PennTex Resources' payment of Wood's attorney's fees and expenses related to his counterclaims in Tsar Case, (c) Wood was required to promptly provide PennTex Resources with a signed release or dismissal of his claims filed in the Tsar Case, (d) Wood was ordered to pay PennTex Resources $217,429 in attorney's fees relating to the federal court litigation that required Wood to appear before the arbitration panel and its release obligation claim, (e) ERG Holdings was ordered to pay PennTex Resources $67,878 for attorneys fees and expenses incurred by PennTex Resources in pursuing its claims against ERG Holdings, (f) Wood was ordered to pay PennTex Resources $14,302 for expenses incurred by PennTex Resources relative to the arbitration proceeding, (g) ERG Holdings was ordered to pay PennTex Resources $7,368 for expenses incurred relative to the arbitration proceeding and (h) Wood and ERG Holdings were ordered to reimburse PennTex Resources the sum of $3,625 for fees and expenses of the American Arbitration Association. As a result of the arbitration panel's award, Wood was required to pay PennTex Resources a total of $141,003 (after deducting legal fees and expenses payable by PennTex Resources to Wood in the amount of $92,540 relative to Wood's counterclaims in the Tsar Case) and ERG Holdings was required to pay PennTex Resources a total of $165,835, thus resulting in a total cash award to PennTex Resources of $306,839.

On September 13, 2007, PennTex Resources filed a motion in the case pending in the U.S. District Court for the Southern District of Texas, Houston Division. The motion sought confirmation of the arbitration award and a final judgment. In the motion, PennTex Resources also sought the dismissal of Shaner as a party to the action, such motion being granted by the court on September 28, 2007. On October 11, 2007, Wood filed a motion seeking to vacate the arbitration award and opposing PennTex Resources' motion to confirm the award. In the motion, Wood moved for vacatur of the award on grounds that the arbitration panel exceeded its powers by issuing a decision based upon clearly erroneous findings of fact. On October 31, 2007, PennTex Resources filed a motion in opposition to Wood's motion to vacate the arbitration award.

PennTex Resources has vigorously opposed Wood's efforts to vacate the arbitration award, and has filed certain other ancillary motions regarding the structure of any final judgment the court might sign confirming the award. As of December 31, 2007, PennTex's motion to confirm the arbitration award, its related motions, and Wood's motion to vacate the arbitration award were all pending before the court. We believe that the likelihood of an unfavorable outcome of this matter is remote.

PennTex Illinois and Rex Operating—EPA Enforcement Matter

In September 2006, the United States Department of Justice ("U.S. DOJ") and the United States Environmental Protection Agency ("U.S. EPA") initiated an enforcement action against PennTex Illinois and Rex Operating seeking mandatory injunctive relief and potential civil penalties based on allegations that the companies were violating the Clean Air Act in connection with the release of hydrogen sulfide (H_2S) gas and other volatile organic compounds ("VOC's") in the course of the companies' oil producing operations near the towns of Bridgeport, Illinois and Petrolia, Illinois. The companies' senior management and representatives of the U.S. EPA, U.S. DOJ, Illinois Environmental Protection Agency ("Illinois EPA") and the Agency for Toxic Substances and Disease Registry ("ATSDR") attended a meeting at the offices of the U.S. EPA in Chicago, Illinois on September 7, 2006, to discuss matters relating to the enforcement action. This meeting had been preceded by certain monitoring of air emissions in the areas surrounding Bridgeport, Illinois and Petrolia, Illinois that the U.S. EPA and ATSDR had conducted in May 2006.

As a result of the initial meeting with the government on September 7, 2006, and certain subsequent meetings and communications with the U.S. EPA and U.S. DOJ, PennTex Illinois and Rex Operating executed a non-binding agreement in principle with the U.S. EPA effective October 24, 2006. In the agreement in principle, PennTex Illinois and Rex Operating agreed to develop and carry out a written response plan designed to further reduce possible emissions of H_2S and VOC's from the companies' oil wells and facilities in the Lawrence Field

that are closest to populated areas. The companies agreed to operate and maintain the control measures described in the response plan in accordance with a written operations and maintenance plan to be developed by the companies and approved by the U.S. EPA. The agreement in principle also required the companies to evaluate the effectiveness of the control measures in the Lawrence Field installed pursuant to the response plan through a monitoring program, and required them to evaluate the need for additional control measures at other facilities within the Lawrence Field within 60 days. The companies also agreed to present to the U.S. EPA any recommendations for further action the companies might develop based upon their observations of the effectiveness of the control measures. The parties each agreed that they would use their best efforts to negotiate a proposed final settlement agreement that would resolve the government's enforcement action, which settlement agreement would be published in the Federal Register and made subject to public comment Before any final approval.

On April 4, 2007, PennTex Illinois, Rex Operating and the U.S. EPA and U.S. DOJ executed a comprehensive consent decree in which PennTex Illinois and Rex Operating, without any admission of wrongdoing or liability and without any agreement to pay any civil fine or penalty, agreed to install certain control measures and to implement certain operating and maintenance procedures in the Lawrence Field. Under the terms of the proposed consent decree, PennTex Illinois and Rex Operating agreed to establish a monitoring protocol that would be designed to facilitate the reduction of possible emissions of H_2S and VOCs from PennTex Illinois' operations near Bridgeport and Petrolia. A notice regarding the proposed consent decree was published in the Federal Register on April 19, 2007. The published notice of the proposed consent decree solicited public comments on the terms of the consent decree for a 30 day period expiring on May 21, 2007. The United States did not receive any comments on the proposed consent decree during the public comment period. On June 1, 2007, the United States filed a motion for the approval and entry of the proposed consent decree with the United States District Court for the Southern District of Illinois. On June 6, 2007, the court granted the United States' motion for approval and entry of the proposed consent decree, thereby resolving the enforcement action according to the terms described in the consent decree. The consent decree does not require us to pay any civil fine or penalty, although it does provide for the possible imposition of specified daily fines and penalties for any violation of the terms and conditions of the consent decree.

As of December 31, 2007, we have substantially met all requirements of the consent decree. In a letter dated February 8, 2008, the U.S. EPA, in consultation with the Illinois EPA, approved our proposed plan and schedule for implementing our H_2S control measures in the Lawrence Field. We will be installing these additional controls throughout 2008, with an expected completion date of December 31, 2008.

PennTex Illinois and Rex Operating—H_2S Putative Class Action Litigation

PennTex Illinois and Rex Operating are defendants in a putative class action lawsuit that has been filed in the United States District Court for the Southern District of Illinois. This action was commenced on October 17, 2006, by plaintiffs Julia Leib and Lisa Thompson, individually and as putative class representatives on behalf of all persons and non-governmental entities that own property or reside on property located in the towns of Bridgeport and Petrolia, Illinois. The complaint asserts that the operation of oil wells that are controlled, owned or operated by PennTex Illinois and Rex Operating has resulted in "serious contamination" of the class area with H_2S. The complaint asserts several causes of action, including violation of the Illinois Environmental Protection Act, negligence, private nuisance, trespass, and willful and wanton misconduct. The complaint was amended in March 2007 to add a claim for alleged violation of Section 7002(a)(1) of the Resource Conservation And Recovery Act. The complaint seeks, among other things, injunctive relief under the Illinois Environmental Protection Act and Illinois common law, compensatory and other damages, punitive damages, and attorneys' fees and costs. In addition, the complaint seeks the creation of a court-supervised, defendant-financed fund to pay for medical monitoring for the plaintiffs and others in the class area. PennTex Illinois and Rex Operating have filed a joint answer to the amended complaint denying virtually all of the allegations in the amended complaint and asserting affirmative defenses thereto.

On December 20, 2006, the plaintiffs filed a motion for class certification requesting that the court certify the case as a class action. On January 26, 2007, the court issued a scheduling and discovery order establishing deadlines for completing discovery and briefing relating to the plaintiffs' motion for class certification. The original order provided for an August 2007 deadline for the completion of pre-certification discovery and the filing of the last brief on class certification issues; however, in August 2007, and again in October 2007, the scheduling and discovery order was amended to extend these deadlines. The final amended scheduling and discovery order provides that plaintiffs' amended motion for class certification must be filed by January 18, 2008 and that defendants' response to such motion must be filed by February 15, 2008. The amended scheduling and discovery order further provides that the court will thereafter schedule a hearing on class certification if it deems that such a hearing is necessary. We intend to vigorously oppose the plaintiffs' motion for certification of the case as a class action.

The parties to this lawsuit have exchanged initial pretrial disclosures as required under the applicable rules, and each side has served and responded to pre-deposition written discovery. In addition, we have deposed each of the named plaintiffs and each of plaintiffs' expert witnesses offered in support of plaintiffs' motion for class certification. The plaintiffs did not elect to depose our expert witnesses offered in support of our opposition to class certification. The final pretrial conference for this case is scheduled for August 7, 2008. The case is scheduled for jury trial on August 18, 2008, in the United States District Court for the Southern District of Illinois located in Benton, Illinois.

We believe that there is no evidence that any H_2S gas emissions from any of our facilities have caused any damage or injury to any person or property, and we intend to vigorously defend against the claims that have been asserted against PennTex Illinois and Rex Operating in this lawsuit. Because this lawsuit is in its initial stages regarding the issue of class certification, however, and because it is usually difficult to predict the outcome of litigation, we are unable to express an opinion with respect to the likelihood of an unfavorable outcome or to estimate the amount or the range of potential loss should the outcome be unfavorable to us.

Pursuant to the terms of a pollution liability policy with Federal Insurance Company, we have insurance coverage for possible damages relating to claims made in this lawsuit for up to $1,000,000. In addition, in accordance with the terms of the pollution liability policy, Federal Insurance Company has agreed to conduct our defense in this lawsuit at the insurer's expense. Under the terms of a written agreement with us, Federal Insurance Company has agreed to pay a substantial portion of our costs and expenses relating to the defense of this lawsuit, including attorneys' fees. Under the terms of our agreement, we are required to pay the costs and expenses relating to the defense in excess of the amounts payable by Federal Insurance Company.

PennTex Illinois—ERG v. Tsar Energy II, LLC

At December 31, 2006, PennTex Illinois was involved in a lawsuit with Tsar Energy II, LLC ("Tsar") and Richard A. Cheatham ("Cheatham") in the 334th Judicial District Court of Harris County, Texas (the "Tsar Case"). The dispute centered around overhead fees charged by PennTex Illinois as operator of jointly-owned oil producing properties located in Illinois and Indiana in which PennTex Illinois owns a 26.0% working interest. Tsar then owned a 49.0% non-operator working interest in the subject properties. PennTex Illinois (then known as ERG Illinois, Inc.) and its former owner, Scott Y. Wood ("Wood"), commenced this litigation in July 2004, by filing a petition against Tsar and its president, Cheatham, seeking, among other things, a declaratory judgment that PennTex Illinois, as the operator of the subject properties, was entitled to charge Tsar and the other non-operators their proportionate shares of a fixed monthly overhead charge of $300 for each producing well located within the North Lawrence Unit portion of the properties pursuant to the terms of a operating agreement relating to such unit.

Tsar filed counterclaims against PennTex Illinois (the known as ERG Illinois, Inc.) asserting (i) a breach of contract and declaratory judgment claim seeking an unspecified amount of actual damages along with declaratory relief based on allegations that PennTex Illinois breached both the joint operating agreement covering the

properties in question and a March 2004 letter of intent that preceded it by charging Tsar its proportionate share of a fixed monthly overhead charge of $300 for each producing well located in the North Lawrence Unit portion of the subject properties, (ii) breach of contract claim seeking $100,000 in actual damages based on Tsar's allegation that PennTex Illinois breached a verbal agreement between the parties relating to an extension fee, (iii) a claim seeking an unspecified amount of actual and punitive damages based on Tsar's assertion that PennTex Illinois committed fraud in the inducement in connection with Tsar's acquisition on March 16, 2004 of its 49.0% non-operating working interest in the subject properties by allegedly making false representations Before and in the letter of intent executed by PennTex Illinois and Tsar and (iv) a conversion claim seeking actual damages of $100,000, plus an unspecified amount of punitive damages, based on Tsar's allegations that PennTex Illinois improperly converted funds belonging to Tsar.

On December 22, 2005, PennTex Illinois filed motions for summary judgment regarding the principal contract claims at issue and the tort counterclaims that had been asserted against it by Tsar. By order signed February 8, 2006, the court granted the PennTex Illinois' motion for summary judgment sustaining its right to charge the non-operators of the subject properties their proportionate shares of a fixed monthly overhead charge of $300 for each producing well located within the North Lawrence Unit. By the same order, the court denied PennTex Illinois' motions for summary judgment seeking dismissal of Tsar's fraud in the inducement and conversion counterclaims. On March 3, 2006, PennTex Illinois and Tsar jointly moved to sever into a separate action, the claims and counterclaims relating to PennTex Illinois' charging of fixed monthly overhead on producing wells in the North Lawrence Unit so that the court would be able to sign a final, appealable judgment in PennTex Illinois' favor on the issues resolved by the court's summary judgment ruling. The court granted this joint motion on March 3, 2006 and the severed action was docketed in the district court as a severed case. On March 31, 2006, Tsar appealed the district court's final judgment in the severed action to the Court of Appeals First District of Texas.

On October 3, 2006, Rex Energy IV acquired the 49.0% working interest of Tsar in the Illinois and Indiana properties at issue in the above cases. As part of this transaction, and without payment of any separate consideration, PennTex Illinois obtained a written settlement agreement requiring Tsar and its principal, Cheatham, to dismiss with prejudice the claims that they had asserted against PennTex Illinois in both the severed and non-severed actions, and to deliver a mutual release releasing PennTex Illinois and certain other affiliates of PennTex Illinois from any and all liability for claims that had been asserted (or could have been asserted) in the two cases by Tsar and Cheatham. Pursuant to this settlement agreement, the claims asserted against PennTex Illinois in the non-severed action were dismissed with prejudice by an order signed on October 5, 2006. On October 26, 2006, the claims asserted against PennTex Illinois in the severed action were dismissed with prejudice by the Court of Appeals First District of Texas, thereby bringing to a final conclusion not only the appellate case, but the underlying severed district court case from which the appeal had been brought.

PennTex Illinois— Tsar's Audit Exceptions Claim

On February 1, 2006, PennTex Illinois was served with a draft audit report prepared by an outside auditor retained by Tsar to audit the joint interest billings that were made by PennTex Illinois. The time period of the audit report was March 1, 2004 through June 30, 2005. The audit report purported to identify potential audit exception claims totaling $17,269,956, plus additional unspecified amounts to be determined.

On February 3, 2006, Tsar filed a formal non-suit without prejudice to its breach of contract counterclaim asserted against PennTex Illinois in the Tsar Case that had sought to recover damages if an accounting of the charges to the joint account revealed that they were inaccurate. On July 31, 2006, PennTex Illinois submitted to Tsar its written response to Tsar's audit report. PennTex Illinois' response alleged that the majority of the audit exceptions set forth in the audit report were unsupported, not evidenced by true audit work, based on supposition and hearsay, and not presented in the manner required by applicable guidance of the Council of Petroleum Accounting Societies ("COPAS"). The majority of the audit exceptions set forth in the report were denied by

PennTex Illinois; however, PennTex Illinois identified costs and expenses totaling $106,616 which were owed to PennTex Illinois by Tsar.

In connection with the settlement of the Tsar lawsuit, PennTex Illinois, without payment of any separate consideration, obtained a full and complete release of the audit exception claims asserted by Tsar in its audit report dated February 1, 2006. This release, which was executed by Tsar on October 3, 2006, was obtained pursuant to the acquisition transaction pursuant to which Rex Energy IV acquired the working interest of Tsar in the jointly-owned oil producing properties located in Illinois and Indiana.

20. SUBSEQUENT EVENTS

On January 3, 2008, we entered into seven derivative commodity transactions. We routinely utilize derivative commodity instruments to minimize the variability in forecasted cash flows due to price movements in oil and natural gas sales. A summary of these derivative positions is as follows:

Commodity	Period	Volume	Floor Price	Ceiling Price
Oil	Jan 08 – Dec 08	60,000 Bbls	$85.00	$107.50
Oil	Jan 09 – Dec 09	60,000 Bbls	$75.00	$107.50
Oil	Jan 10 – Dec 10	120,000 Bbls	$70.00	$107.50
Oil	Jan 11 – Dec 11	120,000 Bbls	$70.00	$106.00
Natural gas	Feb 08 – Dec 08	110,000 MMBTU	$7.00	$9.75
Natural gas	Jan 09 – Dec 09	240,000 MMBTU	$7.50	$10.00
Natural gas	Jan 10 – Dec 10	360,000 MMBTU	$7.50	$10.00

On February 29, 2008, Mr. Thomas F. Shields and Rex Operating, our wholly-owned subsidiary, entered into an Amended and Restated Separation Agreement (the “Amended and Restated Separation Agreement”), which amended and restated a Separation Agreement between the parties entered into on December 17, 2007 (the “Separation Agreement”). The Amended and Restated Separation Agreement amended the original Separation Agreement to provide, among other matters, that Mr. Shields’ date of separation as President of Rex Operating would be advanced from May 30, 2008 to February 29, 2008.

On March 3, 2008, Mr. Lance T. Shaner, our Chairman, executed a Waiver and Cancellation of Stock Option Award, which cancelled the award of 25,000 stock options granted to him on November 7, 2007 at an exercise price of $9.50 per share.

In the putative class action lawsuit filed in the United States District Court for the Southern District of Illinois against PennTex Illinois and Rex Operating, the plaintiffs filed an amended motion for class certification on January 22, 2008. PennTex Illinois and Rex Operating filed a joint motion opposing class certification on February 22, 2008. Plaintiffs filed their reply brief in support of their amended motion for class certification on March 20, 2008. The current scheduling and discovery order issued by the court provides that the court may schedule a hearing on class certification if it deems that such a hearing is necessary. A hearing on class certification has not yet been scheduled by the court. We intend to vigorously oppose the plaintiffs’ motion for certification of the case as a class action.

21. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following tables set forth unaudited financial information on a quarterly basis for each of the last two years.

REX ENERGY CORPORATION

CONSOLIDATED AND COMBINED STATEMENT OF OPERATIONS
($ and Shares in Thousands Except per Share Data)

	Rex Energy Combined Predecessor Companies	Rex Energy Combined Predecessor Companies	Rex Energy Corporation Consolidated and Combined	Rex Energy Corporation Consolidated and Combined
	2007			
	March	June	September	December
OPERATING REVENUE				
Oil and Natural Gas Sales	$12,774	$13,916	$16,591	$ 20,244
Other Revenue	100	113	130	109
Realized Gain(Loss) on Derivatives	265	(647)	(1,593)	(4,223)
TOTAL OPERATING REVENUE	13,139	13,382	15,128	16,130
OPERATING EXPENSES				
Production and Lease Operating Expenses	6,106	6,318	5,910	6,143
General and Administrative Expense	1,982	1,632	1,791	3,182
Accretion Expense on Asset Retirement Obligation	124	130	154	232
Exploration Expense of Oil and Gas Properties	586	1,119	—	1,243
Depreciation, Depletion, and Amortization	3,948	3,705	5,800	5,529
TOTAL OPERATING EXPENSES	12,746	12,904	13,655	16,329
INCOME FROM OPERATIONS	393	478	1,473	(199)
OTHER INCOME (EXPENSE)				
Interest Income	1	—	2	12
Interest Expense	(2,077)	(2,272)	(935)	(362)
Gain on Sale of Oil and Gas Properties	177	15	3	(10)
Unrealized (Loss) Gain on Derivatives	(3,436)	(3,298)	(2,361)	(17,155)
Other Income (Expense)	(44)	(41)	85	171
TOTAL OTHER INCOME (EXPENSE)	(5,379)	(5,596)	(3,206)	(17,344)
NET INCOME (LOSS) BEFORE MINORITY INTEREST AND (PROVISION) BENEFIT FOR TAXES	(4,986)	(5,118)	(1,733)	(17,543)
MINORITY INTEREST SHARE OF (NET INCOME) LOSS	2,728	2,546	878	—
NET INCOME (LOSS) BEFORE INCOME TAX	(2,258)	(2,572)	(855)	(17,543)
Income Tax Benefit (Expense)	—	—	45	6,972
NET INCOME (LOSS)	(2,258)	(2,572)	$ (810)	$(10,571)
Earnings per common share for the five month period ended December 31, 2007:				
Net loss for the quarterly periods	$ —	—	$ (69)	$(10,571)
Basic and fully diluted earnings per share	$ —	—	$ 0.00	$ (0.35)
Weighted average shares of common stock outstanding	—	—	30,795	30,795

REX ENERGY CORPORATION

CONSOLIDATED AND COMBINED STATEMENT OF OPERATIONS
($ and Shares in Thousands Except per Share Data)

	Rex Energy Combined Predecessor Companies	Rex Energy Combined Predecessor Companies	Rex Energy Corporation Consolidated and Combined	Rex Energy Corporation Consolidated and Combined
	2006			
	March	June	September	December
OPERATING REVENUE				
Oil and Natural Gas Sales	9,169	9,811	11,175	13,441
Other Revenue	127	124	107	112
Realized Gain(Loss) on Derivatives	(1,390)	(1,631)	(1,204)	(211)
TOTAL OPERATING REVENUE	7,906	8,304	10,078	13,342
OPERATING EXPENSES				
Production and Lease Operating Expenses	2,444	2,973	4,208	5,609
General and Administrative Expense	844	811	1,008	3,549
Accretion Expense on Asset Retirement Obligation	98	67	90	221
Exploration Expense of Oil and Gas Properties	—	—	—	—
Depreciation, Depletion, and Amortization	1,967	1,735	2,645	4,400
TOTAL OPERATING EXPENSES	5,353	5,586	7,951	13,779
INCOME FROM OPERATIONS	2,553	2,718	2,127	(437)
OTHER INCOME (EXPENSE)				
Interest Income	36	40	4	14
Interest Expense	(766)	(1,199)	(1,507)	(2,638)
Gain on Sale of Oil and Gas Properties	—	90	—	1
Unrealized (Loss) Gain on Derivatives	120	(692)	6,096	(481)
Other Income (Expense)	(113)	(54)	(53)	88
TOTAL OTHER INCOME (EXPENSE)	(723)	(1,815)	4,540	(3,016)
NET INCOME (LOSS) BEFORE MINORITY INTEREST AND (PROVISION) BENEFIT FOR TAXES	1,830	903	6,667	(3,453)
MINORITY INTEREST SHARE OF (NET INCOME) LOSS	921	628	2,541	(1,957)
NET INCOME (LOSS) BEFORE INCOME TAX	909	275	4,126	(1,496)
Income Tax Benefit (Expense)	—	—	—	—
NET INCOME (LOSS)	909	275	4,126	(1,496)
Earnings per common share for the quarterly periods:				
Net loss for the quarterly period	—	—	—	—
Basic and fully diluted earnings per share	—	—	—	—
Weighted average shares of common stock outstanding	—	—	—	—

ITEM 9. CHANGE IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A(T). CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our reports under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms, and that such 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 designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2007, our disclosure controls and procedures were effective.

There were no changes in our internal control over financial reporting during the fourth quarter of 2007 which materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

This annual report does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of the company's registered public accounting firm due to a transition period established by rules of the Securities and Exchange Commission for newly public companies.

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors

Listed below are the Company's five directors, whose terms all expire at the next annual meeting of stockholders.

Name	Age	Position with the Company
Lance T. Shaner	54	Director and Chairman
Benjamin W. Hulburt	34	Director, President and Chief Executive Officer
Daniel J. Churay	45	Director
John W. Higbee	65	Director
John A. Lombardi	42	Director

Lance T. Shaner has been Chairman and a director of the Company since March 2007. Mr. Shaner founded our wholly owned subsidiary, PennTex Resources, L.P., in 1996, and co-founded and served as an officer of all of the Rex Energy affiliated companies before our initial public offering in July 2007. From March 2004 to September 2006, Mr. Shaner served as the Chief Executive Officer and Chairman of our wholly owned subsidiary, Rex Energy Operating Corp. Since its inception in 1984, Mr. Shaner has served as Chairman and Chief Executive Officer of Shaner Hotels, a privately held hotel company. Mr. Shaner received his Bachelor of Arts degree in History from the University of Alfred.

Benjamin W. Hulburt has been a director of the Company since March 2007. Mr. Hulburt was named Chief Executive Officer of the Company in March 2007 and assumed the duties of President of the Company in February 2008. Mr. Hulburt co-founded the first Rex Energy company in 2001 and has co-founded and has served as an officer of all of the Rex Energy affiliated companies since that time. Beginning in March 2004, Mr. Hulburt served as President of Rex Energy Operating Corp. and was named its Chief Executive Officer in October 2006. From January 2001 to February 2004, Mr. Hulburt served as Chief Financial Officer for Douglas Oil & Gas Limited Partnership. Before November 2000, Mr. Hulburt served on active duty as a commissioned officer in the United States Army for four years, leaving the service holding the rank of Captain. Mr. Hulburt received his Bachelor of Science degree in Finance from Pennsylvania State University. Mr. Hulburt is the brother of Christopher K. Hulburt.

Daniel J. Churay has been a director of the Company since October 2007. Since 2002, Mr. Churay has served as the Executive Vice President, General Counsel and Secretary of YRC Worldwide Inc., a publicly traded, Fortune 500 company that is one of the largest transportation services providers in the world. In 2002, Mr. Churay was a Senior Counsel at the law firm of Fulbright & Jaworski L.L.P. From 1998 to 2002, Mr. Churay served as Deputy General Counsel and Assistant Secretary of Baker Hughes Incorporated, a publicly traded supplier of products and technology services and systems to the oil and natural gas industry. From 1995 to 1998, Mr. Churay served as Division Legal Counsel, and later as Chief Corporate Counsel, for Baker Hughes Incorporated. From 1989 to 1995, Mr. Churay was an associate attorney at the law firm of Fulbright & Jaworski L.L.P. Mr. Churay received a B.A. in Economics from The University of Texas at Austin and a Juris Doctorate from University of Houston Law Center.

John W. Higbee has been a director of the Company since October 2007. Mr. Higbee was a partner of Arthur Andersen LLP for over twenty years until his retirement in 2001. At Arthur Andersen, Mr. Higbee served in various management positions, including as the head of the Pittsburgh, Pennsylvania audit practice from 1982 until 1998. Since 2003, Mr. Higbee has served as an independent business consultant to several companies regarding public accounting matters, including Sarbanes-Oxley Act compliance. From September 2004 until August 2006, Mr. Higbee was the Vice President and Chief Financial Officer of the Fullington Auto Bus Company, a privately held company engaged in inter and intra city bus transportation. From April 2002 to August 2003, Mr. Higbee was Chief Financial Officer of Le-Nature's, Inc., a privately held company engaged in the all-natural beverage business. From February 2004 until March 2006, Mr. Higbee was a director and

Chairman of the Audit Committee of World Health Alternatives, Inc., a publicly traded company providing healthcare staffing services to hospitals and other healthcare facilities. From October 2001 to November 2006, Mr. Higbee was a director of Rent-Way, Inc., a publicly traded company that was engaged in the rental-purchase business. Mr. Higbee served on the Audit and Finance committees of Rent-Way's board of directors, becoming the Chairman of the Audit Committee in December 2003. Mr. Higbee received a B.S. in Accounting from The Pennsylvania State University and is a certified public accountant.

John A. Lombardi has been a director of the Company since April 2007. Since March 2008, Mr. Lombardi has been a principal at the accounting firm of Hill, Barth & King LLC in its Erie, Pennsylvania office. From February 2007 until March 2008, Mr. Lombardi was self-employed as an accounting and financial reporting consultant. Mr. Lombardi was the Senior Vice President and Chief Financial Officer for Rent-Way, Inc., a publicly traded furniture and electronics rent-to-own company, from December 2005 to February 2007 when the company was acquired by Rent-A-Center, Inc. He was Vice President, Corporate Controller and Chief Accounting Officer of Rent-Way, Inc. from April 2001 to December 2005. From August 1997 to April 2001, Mr. Lombardi served as the Chief Financial Officer and Treasurer at Community Rehab Centers, Inc. During 1996 and 1997, he served as Executive Vice President, Chief Financial Officer and Treasurer of Northstar Health Services, Inc. From 1986 to 1996, Mr. Lombardi worked in the audit, business advisory and specialty consulting services practices of Arthur Andersen LLP. Mr. Lombardi is a certified public accountant, a certified insolvency and reorganization accountant, and a certified fraud examiner. Mr. Lombardi holds a Bachelor of Science degree from Gannon University.

Executive Officers

The following sets forth certain information regarding executive officers of the Company. The biographies for Lance T. Shaner and Benjamin W. Hulburt, who are each a director and an executive officer of the Company, may be found above in the section entitled "Directors."

Name	Age	Position with the Company
Lance T. Shaner	54	Chairman and Director
Benjamin W. Hulburt	34	President, Chief Executive Officer and Director
Thomas C. Stabley	37	Executive Vice President and Chief Financial Officer
William L. Ottaviani	47	Executive Vice President and Chief Operating Officer
Christopher K. Hulburt	37	Executive Vice President, Secretary and General Counsel
Michael S. Carlson	52	Vice President & Appalachian District Manager
Joe N. Clement	50	Vice President & Southwest Region District Manager
Jack S. Shawver	50	Vice President & Illinois Basin District Manager

Thomas C. Stabley was named the Chief Financial Officer of the Company in March 2007 and was appointed an Executive Vice President in February 2008. Before that, Mr. Stabley served as the Chief Financial Officer of Rex Operating since March 2004 and Vice President of Accounting for Shaner Hotels from January 1998 to March 2004. He received his Bachelor of Science degree in Accounting from the University of Pittsburgh.

William L. Ottaviani was named Chief Operating Officer in November 2007 and Executive Vice President of the Company in February 2008. From September 2007 until his promotion to Chief Operating Officer, Mr. Ottaviani served as Rex Energy's Senior Vice President of Reservoir Engineering. From 1982 until 2007, Mr. Ottaviani served in various management, engineering, operational, and staff positions for Chevron Corporation and its affiliated companies, with assignments in California, Louisiana, Indonesia and Angola. During his Angola assignment from 2002 until 2007, Ottaviani served as both a senior petroleum engineering advisor and asset development manager. He received his Bachelor of Science degree in Petroleum and Natural Gas Engineering from Pennsylvania State University and his M.B.A. from California State University, Bakersfield.

Christopher K. Hulburt was named Executive Vice President, Secretary and General Counsel of the Company in March 2007. Before that, Mr. Hulburt served as the Vice President, Secretary and General Counsel for each of the Predecessor Companies since April 2005. From January 2001 until April 2005, Mr. Hulburt was a senior associate for the law firm of Hodgson Russ LLP in its corporate and securities practice group. Before joining Hodgson Russ, he served as an officer in the U.S. Army's Judge Advocate General's Corps as a military prosecutor beginning in January 1997 and, in his last two years of service, also held the position of Special Assistant United States Attorney for the U.S. Department of Justice. He received his Bachelors degree in History/Education from Niagara University and his law degree from Western New England College School of Law. Mr. Hulburt is the brother of Benjamin W. Hulburt.

Michael S. Carlson was named Vice President & Appalachian Basin District Manager for the Company in March 2007. Before that, Mr. Carlson served as the Vice President of Rex Operating's Northeast Operations since March 2004, and Vice President of Operations for Douglas Oil & Gas from May 1989 to February 2004. He received his Bachelor of Science degree in Geology from the State University of New York at Fredonia.

Joe N. Clement was named Vice President & Southwest Region District Manager of the Company in March 2007. Before that Mr. Clement served as the Permian Basin District Manager for Rex Operating since July 2006, Senior Operations Engineer for Pogo Producing Corp. from April 2006 to July 2006, Senior Operations Engineer for Latigo Petroleum, Inc. from April 2004 to April 2006 and New Mexico Engineer for Saga Petroleum from March 1997 to April 2004. Mr. Clement received his Bachelor of Science degree in Mechanical Engineering from Texas Tech University.

Jack S. Shawver was named Vice President & Illinois Basin District Manager for the Company in March 2007. Before that, Mr. Shawver served as the Vice President of Operations—Illinois Basin for Rex Operating since January 2005, General Manager for ERG Illinois, Inc., an oil and gas company operating in the Illinois Basin, from January 2004 to December 2004, and the Illinois Basin Business Unit Manager for Plains Exploration and Production Company from January 2002 to December 2003. He received his Bachelor of Science degree in Management of Human Resources from the Oakland City University.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires that our executive officers and directors, and persons who own more than 10% of a registered class of the Company's equity securities, file reports of ownership and changes of ownership with the SEC. Officers, directors and greater than 10% shareholders are required by SEC regulation to furnish us with copies of all such forms they file.

Based solely on our review of the copies of such forms received, and on written representations by our officers and directors regarding their compliance with the filing requirements, we believe that during the fiscal year ended December 31, 2007, all reports required by Section 16(a) to be filed by our directors, officers and greater than 10% beneficial owners were filed on a timely basis.

Code of Ethics

We have adopted a code of ethics that applies to our principal executive officer, principal financial officer and principal accounting officer, or persons performing similar functions. A copy is available on the "Corporate Governance" section of the "Investor Relations" section of our website at www.rexenergycorp.com. We intend to make all required disclosures concerning any amendments to or waivers of our code of ethics on our website.

Audit Committee and Audit Committee Financial Experts

The Company's board of directors has a standing Audit Committee. The current members of the Audit Committee are John A. Lombardi (Chair), Daniel J. Churay and John W. Higbee. The Board of Directors has determined that all members of the Audit Committee are independent under the listing standards of the Nasdaq Global Market and also meet the additional criteria for independence of Audit Committee members set forth in Rule 10A-3(b)(l) under the Securities Exchange Act of 1934. In addition, the board of directors has determined that Mr. Lombardi, Mr. Higbee and Mr. Churay qualify as "audit committee financial experts" as defined by the SEC.

ITEM 11. EXECUTIVE COMPENSATION

COMPENSATION DISCUSSION AND ANALYSIS

Overview and Background

The 2007 year was a transformational year for our company. In July 2007, we completed the Reorganization Transactions, whereby we acquired all of the outstanding equity interests of the Predecessor Companies, we completed our initial public offering, and we listed our common stock on the NASDAQ Global Market. This year was also transformational for our compensation practices. Compensation decisions for 2007 were mostly made by our then non-independent Compensation Committee prior to our July 2007 initial public offering. Prior to our initial public offering, our Compensation Committee was comprised of John A. Lombardi, our sole independent director, along with Lance T. Shaner, our Chairman, and Benjamin W. Hulburt, our Chief Executive Officer. In October 2007, two additional independent directors, Daniel J. Churay and John W. Higbee, were appointed to our Board and immediately appointed to the Compensation Committee to replace Mr. Shaner and Mr. Hulburt, each of whom resigned from the committee. Upon these appointments, the Compensation Committee became comprised solely of independent directors.

After these appointments, the newly-independent Compensation Committee took the following actions with respect to 2007 compensation for our named executive officers:

- Reviewed market information compiled by Effective Compensation, Incorporated, a compensation consultant, as described below;
- Awarded discretionary cash bonuses; and
- Reviewed and approved separation arrangements for Thomas F. Shields, our former President and Chief Operating Officer.

Other than these actions, the current Compensation Committee was not involved in making decisions regarding 2007 compensation for our named executive officers. Therefore, the 2007 compensation program may not be indicative of how the Compensation Committee will award compensation to our executive officers in the future as a public company.

Throughout this Compensation Discussion and Analysis, when we refer to the Compensation Committee, we are referring to the independent Compensation Committee which was established in October 2007 when it became comprised solely of independent members. When referring to the Compensation Committee before it became comprised solely of independent members, we will refer to it as the non-independent Compensation Committee.

Compensation Committee

The Compensation Committee has directed the design and implementation of our executive compensation program. Our Compensation Committee is authorized to retain advisors with respect to compensation matters. The Compensation Committee periodically consults with our human resources department and outside advisers and uses survey data that compensation consultants provide in connection with its decisions with respect to executive compensation matters.

Compensation Objectives and Philosophies

Our Compensation Committee has established the following executive compensation objectives:

- Attract and retain talented and experienced executives whose knowledge, skills and performance are critical to our success;
- Motivate and reward executives to attain the highest level of organizational and financial performance; and
- Align the interests of our executives and stockholders to increase stockholder value.

Our Compensation Committee had developed the following philosophies to achieve these objectives:

- Our compensation programs should motivate executives to increase stockholder value and reward them when stockholder value increases;
- Our compensation packages should be competitive while emphasizing pay for performance; therefore, a significant portion of total compensation should be determined by company and individual performance;
- Competitive compensation packages should compensate executives at levels that are reflective of current and responsible market practices;
- Compensation should reflect fairness among the executive management team by recognizing the contributions each executive makes to our success;
- Our compensation program should foster a shared commitment among our executives by coordinating and aligning their company and individual goals; and
- We should compensate our executive officers appropriately to meet our short-term and long-term objectives.

Prior to the formation of the Compensation Committee, the Board and the non-independent Compensation Committee generally had similar objectives and philosophies.

Elements of Our 2007 Executive Compensation Program

Overall, our executive compensation program is designed to be consistent with the objectives and philosophies described above. We have summarized the basic elements of our executive compensation program below and a detailed description of the compensation that we paid to our named executive officers can be found below under "2007 Compensation Program."

Elements of Compensation Program	Description	Key Objectives Promoted
Annual Cash Compensation		
Base Salary	Fixed annual cash compensation paid periodically during the year	To attract and retain talented executives
Cash Bonus	Variable cash compensation based on individual and company performance for a one-year period	To motivate and reward achievement of personal goals, company-wide or business unit strategic, financial or operating goals

Elements of Compensation Program	Description	Key Objectives Promoted
Retirement Benefits		
Retirement Savings Plan	A 401(k) retirement savings plan that enables executives to contribute a portion of their compensation with a company matching contribution	Designed to be market competitive to attract and retain talented executives, given that most of our competitors provide a 401(k) plan
Employment and Severance Benefits		
Employment Agreement	Agreements with our named executive officers providing for minimum salary, incentive opportunities and severance benefits	Designed to enable the company to attract and retain talented executives. Also intended to protect the company's interests through restrictive post-employment covenants, including non-competition and non-solicitation covenants
Long-Term Incentives		
2007 Long-Term Incentive Plan	Stock options, stock appreciation rights, restricted stock, restricted stock units, unrestricted stock, dividend equivalent rights and cash awards	To retain and motivate our executives over a longer term and align their interests with those of the company's stockholders. In 2007, the Compensation Committee did not grant any awards to our named executive officers for the reasons described below under "2007 Compensation Program."
Other Benefits and Perquisites		
Health & Welfare Benefits	Medical, dental and vision care coverage, disability insurance and life insurance	Customary benefits that enable the company to attract and retain executive officers as most companies of our size provide similar benefits
Perquisites	Include use of mobile phones, automobile allowance, club memberships, use of company vehicles	To enhance our ability to attract and retain talented executives

2007 Compensation Program

As described above, compensation for our named executive officers was established, for the most part, before our initial public offering or the formation of the Compensation Committee. Prior to the completion of our initial public offering, our Board and the non-independent Compensation Committee were responsible for our executive compensation program and for approving the compensation awarded to our executive officers. Other than the cash bonuses for 2007 that the Compensation Committee awarded in February 2008, the Board approved all compensation that we awarded to our named executive officers for 2007. As such, compensation for 2007 will not necessarily be indicative of our compensation practices for 2008 and beyond, many of which were established at the end of 2007 and in early 2008. See the section entitled "2008 Compensation Program" for a description of the changes, both already implemented and currently anticipated, to our compensation policies for 2008.

Prior to our initial public offering and the involvement of the Compensation Committee, the Company had no formal policies regarding the amount and mix of compensation paid to our named executive officers. During 2007, the compensation for our named executive officers consisted of two primary components: base salary and a cash bonus. The Compensation Committee did not grant any long-term equity awards to our named executive officers in 2007. Essentially, the Compensation Committee decided to not make any immediate changes to the Company's compensation practices for 2007 because the committee only became independent in late 2007 and desired to take the appropriate time to develop an executive compensation program for 2008 and beyond. The Compensation Committee chose not to grant any long-term incentive awards to the named executive officers in 2007 due to the proceeds realized by our named executive officers by participating in our July 2007 initial public offering as selling stockholders and the continued substantial equity interest in the Company that the named executive officers hold after the initial public offering.

Base Salaries

Our Board and the non-independent Compensation Committee increased the base salaries of our named executive officers in July 2007 based upon individual performance by each of the named executive officers and the input of our Chief Executive Officer. We entered into employment agreements with Benjamin W. Hulburt, Thomas F. Shields, Thomas C. Stabley and Christopher K. Hulburt in August 2007 and with Jack S. Shawver in May 2006. The August 2007 employment agreements reflect the new salaries as minimum base salaries for Messrs. B. Hulburt, Stabley, Shields and C. Hulburt, and the increase in Mr. Shawver's salary was made pursuant to the salary review provisions of his employment agreement.

Annual Base Salaries

Name	2006 Base Salary	2007 Base Salary	Percentage Increase
Benjamin W. Hulburt	$183,602	$202,465	10.3%
Thomas F. Shields	$183,602	$192,369	4.8%
Thomas C. Stabley	$132,600	$155,311	17.1%
Christopher K. Hulburt	$149,224	$170,092	14.0%
Jack S. Shawver	$164,427	$180,002	9.5%

Cash Bonuses

In 2007, each of our named executive officers was eligible to receive a discretionary cash bonus. The cash bonuses for 2007 were not subject to any specific pre-established criteria and no minimums, targets, or maximum amounts were established in advance. In February 2008, the Compensation Committee determined the cash bonus for 2007 for each named executive officer other than Mr. B. Hulburt, our Chief Executive Officer. With respect to Mr. B. Hulburt's bonus, the Compensation Committee made a recommendation to the Board. In an executive session outside the presence of Mr. B. Hulburt, the Board reviewed and approved the Compensation Committee's recommendation and awarded the cash bonus to Mr. B. Hulburt for 2007.

In determining 2007 cash bonuses, the Compensation Committee reviewed an independent market compensation survey compiled by Effective Compensation, Incorporated, or ECI, of oil and gas exploration and production companies including those identified as our peer group, and those with annual revenue of $100 million or less. ECI is an independent compensation consulting company that has not performed other work for the Company. The Compensation Committee determined that for the purposes of benchmarking the Compensation Committee's decisions with regard to a discretionary annual bonus for each named executive officer that this revenue category would be appropriate. In 2007, the Company and its Predecessor Companies had combined revenue of $57.8 million. One hundred twelve oil and gas exploration and production companies were represented in the survey, of which approximately 24 had revenues of less than $100 million. The

Compensation Committee used the survey data to assist it with determining 2007 bonuses that rewarded the named executive officers for their performance while remaining within the parameters of being consistent with responsible market practices. In reviewing the ECI survey data, the Compensation Committee compared possible bonuses for our named executive officers against the bonuses that companies in the survey data provided their executives in each position as well as the impact on total cash compensation for each position both at the 50th and 75th percentile levels of all companies in the survey.

The Compensation Committee then reviewed the performance of each named executive officer in 2007 with our Chief Executive Officer, including formal performance reviews conducted by the Chief Executive Officer. In an executive session outside the presence of our Chief Executive Officer, the Compensation Committee reviewed the performance of our Chief Executive Officer for 2007. These performance reviews included a review of our financial performance, along with the individual named executive officer's performance. In general, the Compensation Committee believed that the executive team had performed exceptionally well in 2007, as the Company experienced an increase in production and generally met our financial plan, even while we completed the Reorganization Transactions and our initial public offering. Against this overall assessment, the Compensation Committee considered each named executive officer's contribution in 2007, including the role each named executive officer took in the Reorganization Transactions and our initial public offering.

The Compensation Committee then determined to award, and in the case of our Chief Executive Officer to recommended to the Board to award, the cash bonuses for our named executive officers described in the table below. The Board, outside the presence of our Chief Executive Officer, then approved the Compensation Committee's recommendation with respect to our Chief Executive Officer's bonus and awarded the bonus for him described in the table below. These cash bonuses, when taken together with the 2007 base salaries earned by our named executive officer, generally provided them total cash compensation between the 50th and 75th percentiles of the companies in the ECI survey group. The Compensation Committee believes that this compensation is appropriate for the high level of performance of the named executive officers in 2007 and that the ECI survey data, as a benchmark, demonstrates that the level of compensation is within responsible market practices in the industry and for such a level of performance.

In December 2007, Mr. Shields announced his resignation from the Company to be effective as of May 30, 2008. We entered into a separation agreement with Mr. Shields, which was amended in February 2008, when Mr. Shields accelerated his last day of employment with the Company. Pursuant to the separation agreement with Mr. Shields, we agreed that his 2007 discretionary cash bonus would not be less than 15% of his annual base salary for 2007, which is the amount the Compensation Committee awarded Mr. Shields.

Name	2007 Bonus Award	2007 Bonus Award as a Percentage of Base Salary
Benjamin W. Hulburt	$113,380	56%
Thomas F. Shields	$ 28,885	15%
Thomas C. Stabley	$ 69,890	45%
Christopher K. Hulburt	$ 76,541	45%
Jack S. Shawver	$104,001	58%

Other Benefits and Perquisites

Our named executive officers are eligible to participate in various benefit plans generally available to all of our employees. Under these plans, our named executive officers are entitled to medical, dental and vision care coverage, disability insurance and life insurance. The Compensation Committee believes that our commitment to provide these benefits demonstrates our recognition that the health and well-being of our employees contribute directly to a productive and successful work life that enhances results for the Company and our stockholders. In

addition, the Company provides to all of our key employees, including our named executive officers, company paid mobile phones. The Company also provides to each of Messrs. B. Hulburt, Stabley and C. Hulburt an automobile allowance of $500 per month. The Company provides access to and use of a company vehicle to Mr. Shawver. For additional information regarding benefits and perquisites, see "Executive Compensation – All Other Compensation" on page 119 of this report.

2008 Compensation Program

Compensation Committee's Role in Establishing Compensation

Since October 2007, the Compensation Committee has played a prominent role in determining the compensation of our executives. Since that time, the Compensation Committee has developed formal objectives and philosophies for executive compensation and worked to establish a compensation program for our executives for 2008 in accordance with these objectives and philosophies.

The Compensation Committee is responsible for determining and evaluating the executive compensation of our executives, including the named executive officers. We anticipate that the Compensation Committee will review our compensation objectives and philosophies and our executive compensation program on an annual basis to determine if our program is effective in achieving the objectives and philosophies. We anticipate that our Compensation Committee will continue our practice of making executive salary decisions annually. At such time, the Compensation Committee may determine the amount and mix of total compensation to be paid to our executives, including our named executive officers. The Compensation Committee may examine and consider our performance during the previous year in establishing the current year's compensation.

In addition, the Compensation Committee may generally solicit the input of our Chief Executive Officer as to the compensation of our executives, including our named executive officers, other than his own compensation. Our Chief Executive Officer expects to annually review the performance of each executive with the Compensation Committee and make recommendations to the Compensation Committee regarding various elements of compensation for each executive.

The Compensation Committee may also review data that our human resources department compiles with respect to the executive compensation policies of our peer group and industry practices. In addition, and as described below, the Compensation Committee retained ECI in December 2007 to provide the committee with independent market survey information. The Compensation Committee may continue to rely on information provided by ECI in order to ensure that our compensation practices are competitive with those of our peers.

To attract and retain talented and experienced executives whose knowledge, skills and performance are critical to our success, the Compensation Committee believes that we should competitively and fairly compensate our executives each year relative to market pay levels of our peer group and the internal pay levels of our executive officers. In determining compensation changes for our executives, including our named executive officers, we may take into account market pay levels of our peer group as a benchmark to determine the competitive landscape for executive talent as well as responsible market pay practices. However, the Compensation Committee has not targeted any particular average, percentile level or other metric that the data may suggest. Rather, the Compensation Committee intends to exercise its discretion when making compensation decisions to consider the following factors, among any others that circumstances may suggest from time to time:

- market levels of compensation for positions comparable to the executive's position;
- the executive's contributions and performance;
- the executive's roles and responsibilities, including the executive's tenure in such role;
- the Company's needs for the executive's skills;

- the executive's experience and management responsibilities;
- the executive's prior compensation amount and mix; and
- the executive's potential and readiness to contribute in the executive's current role as well as future roles.

The Compensation Committee has not given any particular weight to any of these factors, but may consider them as appropriate. All pay elements are cash-based except for the long-term equity incentive program, which may be an equity-based or cash award or a combination of both. We believe that a substantial portion of each named executive officer's compensation should be performance-based.

The Compensation Committee recognizes that there may be instances where the accounting treatment of a compensation element may have a disproportionate impact on our financial results in any given year, irrespective of whether or not such accounting impact truly reflects our operating results for that fiscal year, as is the case with changes in our accruals for insurance and legal liabilities. Accordingly, the Compensation Committee uses its discretion in evaluating our financial performance with respect to our annual incentive compensation and our long-term incentive compensation, and may exclude certain accounting measures and extraordinary items in determining whether we met our financial performance target when doing so is consistent with our compensation objectives.

Advisor to the Compensation Committee.

To assist the Compensation Committee in assessing and determining compensation packages, the Compensation Committee may engage compensation consultants. In December 2007, the Compensation Committee retained ECI to provide a market analysis to the Compensation Committee for the purpose of assisting the Compensation Committee in making compensation determinations for our executive officers for 2008. ECI was engaged to provide an independent market compensation survey, which included information on oil and gas exploration and production companies with annual revenue of $100 million or less. The information provided by ECI included a comparison of our executive compensation program, including total compensation opportunities and individual pay components (e.g., base salary, short-term incentive and long-term equity-based compensation) as compared to companies in our peer group identified below. The results of this study were presented to the Compensation Committee, which used the information as a factor in setting executive compensation for 2008.

Benchmarking and Peer Group

The Compensation Committee directed ECI to compare the amount and mix of compensation that we pay to our executives to executives of a selected group of similarly-positioned companies in our industry, as well as to their industry wide compensation survey for oil and gas companies with revenues less than $100 million. For 2008, the group of publicly-traded oil and gas companies, which were selected as our primary peer group, were:

- Warren Resources, Inc.
- NGAS Resources, Inc.
- Edge Petroleum Corp.
- TXCO Resources, Inc.
- Cano Petroleum
- Callon Petroleum
- Clayton Williams Energy, Inc.
- Energy Partners, Ltd.
- Parallel Petroleum
- Goodrich Petroleum Corp.
- Kodiak Oil & Gas Corp.

At the time of the study, each of these companies had a market capitalization of less than $1 billion. The Company's market capitalization at that time was also below $1 billion. The Compensation Committee believed these companies provided a relevant benchmark for comparing our executive officers' compensation to the compensation of our competitors. These competitors are generally comparable in size, operations, revenues and

reserves to us and require executives with similar experience. In addition, we compete against them for employees in all areas and at all levels of expertise, experience and abilities. Our goal in comparing the compensation of our executives to those of our peer group, as well as to the industry survey of companies with revenues less than $100 million, is to benchmark the total compensation of our executives to determine if it is competitive as well as within responsible pay levels.

Base Salaries

The Compensation Committee determined, based on its review of the ECI studies, that the salaries of several of our named executives fell below the average of the peer group and below the 50th percentile of the survey of companies with revenues less than $100 million. Based on the ECI analysis, the Compensation Committee approved the following increases in base salary for our named executives, effective as of March 1, 2008:

Annual Base Salaries

Name	2007 Base Salary	2008 Base Salary	Percentage Increase
Benjamin W. Hulburt	$202,465	$270,000	33.4%
Thomas F. Shields(1)	$192,369	—	—
Thomas C. Stabley	$155,311	$210,000	35.2%
Christopher K. Hulburt	$170,092	$210,000	23.5%
Jack S. Shawver	$180,002	$190,000	5.6%

(1) Mr. Shields resigned from the company effective February 29, 2008.

These salaries are generally below or at the 50th percentile of the companies in the ECI survey group. Although the new salary for the Chief Executive Officer is well below the 50th percentile of the ECI survey group, the Compensation Committee significantly increased the Chief Executive Officer's salary and set the Chief Executive Officer's annual bonus opportunity such that if the Chief Executive Officer and the Company meet their performance goals, the Chief Executive Officer's total compensation will be around the 50th percentile of the ECI survey group. The Compensation Committee believes that these salaries are appropriate and that the ECI survey data, as a benchmark, demonstrates that the salary levels are within responsible market practices in the industry.

Annual Incentive Compensation

In 2008, our executives will be eligible for annual incentive compensation awards. At the beginning of 2008, the Compensation Committee established target bonus rates for our executives as illustrated in the table below. The target awards were set as a percentage of base salary, as was previously done with our annual cash bonus awards.

Group	Target Bonus as a % of Base Salary
Chief Executive Officer	70%
Executive Vice Presidents	45%
Vice Presidents (Business Unit Managers)	40%
Vice Presidents (Non-Business Unit Managers)	30%

For 2008, the Compensation Committee set company-wide financial and operational performance targets for our executives. The Compensation Committee determined that 50% of the executive's annual incentive

compensation will be determined based on these targets and 50% will be determined based on individual performance. If an executive is also a business unit manager, then 50% of the financial performance measure will be based on the performance of the executive's business unit. The Compensation Committee believes that the performance targets are accurate indicators of the executive's impact on our operational success and provide specific standards that we believe will motivate our executives to perform in our best interest and in our stockholders' best interests. Specifically, the company-wide financial and operational performance targets include measures that the Compensation Committee believes will increase the value of the Company, including operating cash flow, total net production, year-over-year proven reserve growth, lease operating expenses, capital budget items variance, general and administrative expenses and activity level. In our planning process, we develop both "risked" and "un-risked" business plans for the upcoming year. The risked plans are developed using certain assumptions concerning our drilling projects, whereby, in general, the forecasted production from our exploratory drilling projects are more heavily risked than the forecasted production from our developmental drilling projects.

To determine performance against these financial and operational targets, the Compensation Committee will determine an overall performance rating based on the average of the actual results of each of these target measures. The Compensation Committee has set three achievement levels to be used as a guideline for the portion of the executive's bonus attributable to the achievement of these targets. The following table illustrates the three achievement levels:

Achievement Level	% of Target Bonus Awarded	Description
Threshold	37.5% *(50% of 75%)*	Average of 90% of the company's risked-plan financial and operational targets are met
Expected	50% *(50% of 100%)*	Average of 100% of the company's risked-plan financial and operational targets are met
Exceeded	100%+ *(50% of up to 200%)*	Average of greater than 100% of the company's unrisked-plan financial and operational targets are met

The Compensation Committee will award the other 50% of each executive's target bonus based on each individual executive's performance, which will include an evaluation of the executive's achievement of the executive's personal objectives that the Chief Executive Officer sets for each executive at the beginning of the year or, in the case of the Chief Executive Officer, the Board establishes for the Chief Executive Officer. The Compensation Committee may determine bonuses for the individual performance component above or below the target level, taking into account the individual executive performance and the Company's results of operations and financial position at the time bonuses are awarded.

These changes were made to our cash incentive program after consultation with the Compensation Committee's compensation consultant, ECI, and were to bring our compensation practices more in line with those of our peers. By establishing performance metrics for our executives in the beginning of the year, the Compensation Committee also believes these executives will be better motivated to achieve individual and company performance measures that company management, along with the Compensation Committee, have deemed important to our success.

Long-Term Incentive Compensation

Beginning in 2008, the Compensation Committee implemented a policy to consider grants of long-term equity or incentive awards to our executives under our 2007 Long-Term Incentive Plan, generally to occur in

February of each year. Under our 2007 Long-Term Incentive Plan, the Compensation Committee may grant stock options, stock appreciation rights, restricted stock, restricted stock units, unrestricted stock, dividend equivalent rights and cash awards to our named executive officers.

On February 19, 2008, based in part on the recommendations of our Chief Executive Officer, the Compensation Committee granted stock appreciation rights ("SARs") to our named executive officers (other than Mr. Shields) under our 2007 Long-Term Incentive Plan. In determining to issue stock appreciation rights to our named executive officers, the Compensation Committee considered its objectives to provide long-term incentive compensation to align the interests of these officers with our stockholders and also considered that several of our named executive officers hold significant amounts of our common stock. In addition, the Compensation Committee determined that the use of SARs would be more advantageous to the company than stock options because the SARs would be paid in cash and, therefore, are less dilutive to the company's stockholders than are stock options.

The following table shows the number of SARs issued to the named executive officers on February 19, 2008:

Name	Number
Benjamin W. Hulburt	32,500
Thomas F. Shields(1)	—
Thomas C. Stabley	20,500
Christopher K. Hulburt	20,500
Jack S. Shawver	18,000

(1) Mr. Shields resigned from the company effective February 29, 2008.

The SARs entitle a participant to surrender any then exercisable portion of the SAR in exchange for an amount in cash equal to the product of:

- the excess of the fair market value of a share of our common stock on the date preceding the date of surrender over the fair market value of a share of our common stock on the date the SAR was issued, and
- the number of shares of our common stock subject to the SAR.

The SARs have a grant price equal to $13.56, the closing price of our common stock on the NASDAQ Global Market on February 19, 2008. The SARs vest and become exercisable on February 19, 2011, the third anniversary of the grant date, provided the named executive officer remains employed by us on that date. The SARs vest and become immediately exercisable upon a change in control of the company, as such term is defined in our 2007 Long-Term Incentive Plan. Unless sooner terminated, the SARs expire on February 18, 2018.

Stock Ownership Guidelines

The Compensation Committee has not implemented stock ownership guidelines for our executive officers. The Compensation Committee presently intends to periodically review best practices and reevaluate our position with respect to stock ownership guidelines.

Tax Deductibility of Executive Compensation

Limitations on deductibility of compensation may occur under Section 162(m) of the Internal Revenue Code of 1986, which generally limits the tax deductibility of compensation paid by a public company to its Chief

Executive Officer and certain other highly compensated executive officers to $1 million in the year the compensation becomes taxable to the executive officer. There is an exception to the limit on deductibility for performance based compensation that meets certain requirements.

Although deductibility of compensation is preferred, tax deductibility is not a primary objective of our compensation program. We believe that achieving our compensation objectives set forth above is more important than the benefit of tax deductibility and we reserve the right to maintain flexibility in how we compensate our executive officers, which may result in limiting the deductibility of amounts of compensation from time to time.

Conclusion

The Compensation Committee believes the compensation provided to our executive officers is reasonable and appropriate to facilitate the achievement of our short-term and long-term objectives. The compensation programs and policies that our Compensation Committee has designed effectively incentivize our executive officers on both a short-term and a long-term basis to perform at a level necessary to achieve these objectives. The various elements of compensation combine to align the best interests of our executive officers with our stockholders and our company in order to maximize stockholder value.

EXECUTIVE COMPENSATION

Summary Compensation Table

The following table sets forth the total compensation awarded to, earned by, or paid to our named executive officers for all services rendered in all capacities to us in 2007.

Name and Principal Position	Year	Salary	Bonus(1)	All Other Compensation(2)	Total
Benjamin W. Hulburt,	2007	$202,465	$113,380	$46,423	$362,268
President and Chief Executive Officer(3)	2006	$183,602	$ 25,000	$26,730	$235,332
Thomas F. Shields,	2007	$192,369	$ 28,885(5)	$14,418	$235,672
President(4)	2006	$183,602	$ 15,000	$13,616	$212,218
Thomas C. Stabley,	2007	$155,311	$ 69,890	$14,066	$239,267
Executive Vice President and Chief Financial Officer	2006	$132,600	$ 15,000	$15,175	$162,775
Christopher K. Hulburt,	2007	$170,092	$ 76,541	$31,459	$278,092
Executive Vice President, Secretary and General Counsel	2006	$149,224	$ 15,000	$18,546	$182,770
Jack S. Shawver,	2007	$180,002	$104,001	$11,500	$295,503
Vice President & Illinois Basin District Manager	2006	$164,427	$ 65,000	$16,271	$240,898

(1) Represents for our named executive officers, the cash bonus amount determined by our Compensation Committee with respect to services for the year indicated. See "Compensation Discussion and Analysis -2007 Compensation Program – Cash Bonuses" on page 111 of this report.
(2) For 2007, represents the compensation as described under the caption "All Other Compensation" below.
(3) Following the resignation of Mr. Shields, Mr. Benjamin Hulburt assumed the duties of President on February 29, 2008.
(4) During 2006 and until November 20, 2007, Mr. Shields also served as our Chief Operating Officer.
(5) Mr. Shields resigned from the company effective February 29, 2008. Pursuant to an amended and restated separation agreement entered into with Mr. Shields on February 29, 2008, we agreed that Mr. Shields' 2007 annual bonus award would not be less than fifteen percent of his annual base salary for 2007.

All Other Compensation

The following table provides information regarding each component of compensation for 2007 included in the All Other Compensation column in the Summary Compensation Table above.

Name	Company 401(k) Contributions(1)	Automobile-Related Expenses(2)	Club Membership Fees	Other(3)	Total
Benjamin W. Hulburt	$10,123	$5,300	$1,000	$30,000	$46,423
Thomas F. Shields	$ 9,618	$4,800	$ 0	$ 0	$14,418
Thomas C. Stabley	$ 7,766	$5,300	$1,000	$ 0	$14,066
Christopher K. Hulburt	$ 7,159	$5,300	$1,000	$18,000	$31,459
Jack S. Shawver	$11,500	$ 0	$ 0	$ 0	$11,500

(1) Represents company contributions to our 401(k) plan.
(2) Represents (a) for Mr. Benjamin Hulburt, Mr. Stabley and Mr. Christopher Hulburt, an automobile allowance, paid monthly in 2007 and (b) for Mr. Shields, his use of a company-owned vehicle during 2007.

(3) Represents for Mr. Benjamin Hulburt and Mr. Christopher Hulburt forgiveness of relocation loans which were made by the company prior to our initial public offering.

The following is a description of material factors necessary to understand the information disclosed above in the Summary Compensation Table.

Employment Agreements with Benjamin W. Hulburt, Thomas F. Shields, Thomas C. Stabley and Christopher K. Hulburt

In July 2007, we entered into employment agreements with each of Benjamin W. Hulburt, Thomas F. Shields, Thomas C. Stabley and Christopher K. Hulburt. The employment agreements provided for an annual base salary of $225,000 for Benjamin K. Hulburt, $200,000 for Thomas F. Shields, and 185,000 for each of Thomas C. Stabley and Christopher K. Hulburt. Each employment agreement became effective on the date our initial public offering was consummated and will continue in effect until the earlier of (1) the third anniversary of the effective date of the employment agreement, (2) termination based on death or disability of the executive, (3) termination by us of the executive's employment, and (4) voluntary termination of employment by the executive. If the executive is employed on the third anniversary of the effective date of the employment agreement, his employment agreement will be automatically extended for a one year period unless we provide the executive timely written notice that we do not intend to extend the term. Mr. Shields resigned from the Company effective February 29, 2008. See "Potential Payments Upon Termination or Change-In-Control– Separation Agreement With Our Former President."

Employment Agreement with Jack S. Shawver

In May 2006, we entered into an amended and restated employment agreement with Jack S. Shawver relating to service as our Vice President of Operations—Illinois Basin. This agreement amended and restated an employment agreement entered into on June 1, 2005. The employment agreement, as amended, provides for a minimum annual base salary of $180,000, and will continue in effect until the earlier of (1) June 1, 2008, (2) termination based on death or disability of Mr. Shawver, (4) termination by us of Mr. Shawver's employment and (4) voluntary termination of employment by Mr. Shawver.

Potential Payments Upon Termination or Change-In-Control

Employment Agreements with Benjamin W. Hulburt, Thomas C. Stabley and Christopher K. Hulburt

Each employment agreement provides that we will pay severance benefits to each executive officer if (i) his employment is involuntarily terminated without cause, (ii) he elects to terminate his employment with good reason (as further set forth in the employment agreement), or, (iii) if following a change in control (as defined in the employment agreement and described below), he elects to terminate his employment with good reason (as further set forth in the employment agreement) in connection with a change in control.

In each such instance, and subject to the terms of the employment agreements, we will pay to the applicable executive officer the following:

- A lump sum in cash equal to the sum of his base salary through the date of termination, any compensation previously deferred by him (together with any accrued interest or earnings thereon) and any accrued vacation pay, to be paid within 30 days following the date of termination;
- All vested benefits to which he is entitled under the terms of the employee benefit plans in which he is a participant on the date of such termination, payable when due under the terms of the plans;
- A lump sum cash severance payment in an amount equal to two times his then base salary, to be paid within 60 days following the date of termination;
- A lump sum in cash equal to the expected value of his annual cash incentive potential for the fiscal year in which such termination occurs prorated to the date of termination, to be paid within 60 days following the date of termination;

- A lump sum equal to the product of (1) the monthly basic life insurance premium applicable to his basic life insurance coverage immediately prior to the date of termination and (2) the number of full and fractional months remaining under the term of the applicable employment agreement; and

- Certain perquisites, other than executive life insurance, being provided to the executive on the date of termination as further set forth in each agreement for the remainder of the term of the applicable employment agreement.

Each employment agreement also provides that, upon a change in control, (i) all options to acquire any of our stock and all stock appreciation rights held by the executive officer will become fully exercisable, and (ii) all restrictions on any of our restricted stock granted to the executive officer prior to the change in control will be removed and the stock will be freely transferable, in each case, regardless of whether the conditions set forth in the relevant award agreements have been fully satisfied.

Under the employment agreements, a "change in control" means:

- Our board of directors is no longer comprised of a majority of incumbent directors, who are defined as directors who were directors on the effective date of the agreements and any successor to an incumbent director whose election, or nomination for election by our stockholders, was approved by the affirmative vote of at least two-thirds of the incumbent directors then on the board of directors; or

- The Company is reorganized, merged or consolidated or the Company or any of our subsidiaries is sold, or all or substantially all of our assets are disposed of, unless (1) all or substantially all of the individuals and entities who were the beneficial owners of our outstanding common stock immediately prior to such transaction beneficially own, directly or indirectly, more than 50% of the then outstanding shares of our common stock of the corporation resulting from such transaction in substantially the same proportions as their ownership immediately prior to such transaction of our outstanding common stock, (2) an individual, entity or group (within the meaning of Section 13(d)(3) or 14(d)(2) of the Exchange Act) (excluding any employee benefit plan (or related trust) of the Company or such corporation resulting from such Business Combination) beneficially owns, directly or indirectly, 30% or more of the then outstanding shares of common stock of the corporation resulting from such transaction, except to the extent that such ownership existed prior to such transaction, and (3) at least a majority of the members of the board of directors of the corporation resulting from such transaction were incumbent directors of our board of directors at the time of the execution of the initial agreement, or of the action of our board of directors, providing for such transaction; or

- Any individual, entity or group (within the meaning of Section 13(d)(3) or 14(d)(2) of the Exchange Act) acquires beneficial ownership of 30% or more of the then outstanding shares of our common stock, except for (1) any acquisition directly from us, (2) any acquisition by us, (3) any acquisition by any employee benefit plan (or related trust) sponsored or maintained by us or any entity controlled by us, or (4) any acquisition by any corporation pursuant to a transaction which complies with clauses (1), (2) and (3) of the immediately preceding paragraph.

The employment agreements also (i) prohibit the executive officers from disclosing our confidential information, and, (ii) subject to certain exceptions as further set forth in each employment agreement, restrict each executive officer from engaging in any practice or business in competition with us or our affiliates for a period of one year following the date of such executive officer's termination of employment with us.

Employment Agreement with Jack S. Shawver

In the event that Mr. Shawver's employment pursuant to the employment agreement is terminated for cause, Mr. Shawver will receive all accrued but unpaid salary through the date of termination. In the event that

Mr. Shawver's employment pursuant to the employment agreement is terminated by us other than for cause, Mr. Shawver will continue to receive payments of base salary for the lesser period of (i) one year or (ii) the remaining term of the employment agreement, and any benefits that he would have been entitled to under the employment agreement for such period. In the event that Mr. Shawver's employment pursuant to the employment agreement is terminated as a result of voluntary termination by Mr. Shawver, he will receive no salary or other benefits pursuant to the employment agreement other than accrued but unpaid base salary and accrued benefits.

The employment agreement with Mr. Shawver also prohibits him from disclosing our confidential information and, subject to certain exceptions as further set forth in the agreement, restricts him from engaging in any practice or business in competition with us or our affiliates anywhere within a two mile radius of any area of mutual interest or leasehold interest in which we or our affiliates has or had an ownership interest during the term of the employment agreement for a period of one year after the last period for which Mr. Shawver receives compensation pursuant to the employment agreement.

Termination and Change in Control Table for 2007

The following table summarize the compensation and other benefits that would have become payable to each named executive officer (other than Mr. Shields) assuming his employment agreement were effective, as of January 1, 2007, his employment had terminated on December 31, 2007, given the named executive officer's base salary as of that date, and, if applicable, the closing price of the company's common stock on December 31, 2007, which was $11.93. In addition, the following table summarizes the compensation that would become payable to each named executive officer (other than Mr. Shields) assuming that a change in control of the company had occurred on December 31, 2007. As of December 31, 2007, none of our named executive officers had any outstanding equity awards under our 2007 Long-Term Incentive Plan or otherwise.

Under the employment agreements described above, if benefits to which the executive becomes entitled are considered "excess parachute payments" under Section 280G of the Tax Code, then the executive will be entitled to an additional "gross-up" payment from us in an amount such that, after payment by the executive of all taxes, including any excise tax imposed upon the gross-up payment, he retains an amount equal to the excise tax imposed upon the payment. The following table shows the potential gross-up payment the company would have to pay to the following named executives in the event of a change of control as of December 31, 2007.

Due to the factors that may affect the amount of any benefits provided upon the events described below, any actual amounts paid or payable may be different than those shown in this table. Factors that could affect these amounts include the date the termination event occurs, the base salary of an executive on the date of termination of employment and the price of our common stock when the termination event occurs.

In the event of involuntary termination without cause, voluntary termination for good reason or voluntary termination for good reason following a change in control, we would owe the following amounts:

Name	Severance Amount Pursuant to Employment Agreement	Bonus Amount Pursuant to Employment Agreement	Benefit Payments Pursuant to Employment Agreement	Estimated Gross-Up Payments Pursuant to Employment Agreements	Total Payments Pursuant to Employment Agreements
Benjamin W. Hulburt	$540,000	$378,000	$162,000	$27,700	$1,107,700
Thomas C. Stabley	$420,000	$189,000	$126,000	$17,500	$ 752,500
Christopher K. Hulburt	$420,000	$189,000	$126,000	$17,500	$ 752,500
Jack S. Shawver	$190,000	$ 76,000	$ 57,000	$15,400	$ 338,400

Separation Agreement with Our Former President

On December 17, 2007, Mr. Thomas F. Shields, our former President, resigned as a member of our Board of Directors. In addition, pursuant to the terms of a separation agreement that we entered into with Mr. Shields,

Mr. Shields resigned his position as our President effective May 30, 2008. On February 29, 2008, we entered into an amended and restated separation agreement with Mr. Shields, which amended the original separation agreement to provide, among other matters, that Mr. Shields' date of separation as our President would be accelerated from May 30, 2008 to February 29, 2008.

Under the amended and restated separation agreement, Mr. Shields will receive a severance payment in an amount equal to three-quarters of his annual base salary for fiscal year 2008 payable in a single lump sum payment on September 1, 2008. In addition, we agreed to pay the costs of medical insurance benefits for Mr. Shields and his dependents and the cost of Mr. Shield's basic life insurance coverage for a period of nine months following the date of separation in a single lump sum payment on September 1, 2008. The amended and restated separation agreement also provides that Mr. Shields would receive an annual bonus for fiscal year 2007 in a single lump sum payment at a time and in a manner consistent with the company's customary practices of an amount not less than fifteen percent of his annual base salary for fiscal 2007.

In March 2008, Mr. Shields received an annual bonus for fiscal year 2007 of $28,885. On September 1, 2008, Mr. Shields will receive a severance payment of $150,000 and a payment of $8,339 for the cost of the medical and life insurance benefits described above.

The amended and restated separation agreement provides that the compensation and benefits payable to Mr. Shields under the amended and restated separation agreement are in lieu of any other severance benefits to which he may otherwise be entitled pursuant to his employment agreement dated August 1, 2007 or any other employment agreement or severance plan, program, policy or arrangement of the company. The amended and restated separation agreement provides that Mr. Shields will be subject to the non-competition provisions of the employment agreement until November 30, 2008 and the non-solicitation provisions of the employment agreement until May 30, 2009.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

None of our executive officers serves as a member of our board of directors or compensation committee, or other committee serving an equivalent function, of any other entity that has one or more of its executive officers serving as a member of our board of directors or compensation committee.

COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

The Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussions, the Compensation Committee recommended to the Board that the Compensation Discussion and Analysis be included in this annual report on Form 10-K.

THE COMPENSATION COMMITTEE

Daniel J. Churay, Chairman
John W. Higbee
John A. Lombardi

DIRECTOR COMPENSATION

Cash Compensation

In 2007, each of our non-employee directors received a monthly cash retainer of $5,000. In addition, until our initial public offering in July 2007, Mr. Shaner, our Chairman, received a salary for serving in such capacity. After such time, Mr. Shaner received the monthly $5,000 cash retainer as a non-employee director.

Since our initial public offering in July 2007, we have not paid fees to directors who are employees of the Company. In 2007 our directors received no additional compensation for serving on committees of our board or as a chairman of any committee.

Equity-Based Compensation

In 2007, we granted Mr. Lombardi options to purchase 75,000 shares of our common stock and each of Mr. Churay and Mr. Higbee options to purchase 25,000 shares of our common stock. Mr. Lombardi received more options than our other non-employee directors as he joined our board in April 2007 and served as a director during the Reorganization Transactions and our initial public offering, whereas Messrs. Churay and Higbee joined our Board in October 2007. Mr. Shaner received options to purchase 25,000 shares of our common stock in November 2007, which were all subsequently cancelled in March 2008 at the request of Mr. Shaner. See footnote 3 in the table below.

The following table sets forth certain information regarding the compensation of our non-employee directors during 2007.

Director Compensation

Name	Fees Earned or Paid in Cash	Option Awards(3)	Total
Lance T. Shaner(1)	$178,439	—	$178,439
Daniel J. Churay	$ 12,258(2)	$ 5,965	$ 18,223
John W. Higbee	$ 12,258(2)	$ 5,965	$ 18,223
John A. Lombardi	$ 40,000(2)	$17,895	$ 57,895

(1) For Mr. Shaner, represents salary for serving as Chairman, which he received until our initial public offering in July 2007, and a monthly retainer of $5,000 for the remainder of the year.

(2) Represents the aggregate of the $5,000 monthly cash retainer for non-employee directors in 2007.

(3) Represents the expense recognized for financial reporting purposes for 2007 with respect to awards of options to purchase shares of our common stock granted to each of Messrs. Churay, Higbee and Lombardi. These dollar amounts were computed in accordance with Financial Accounting Standards Board Statement No. 123(R), Share-Based Payment. The aggregate number of stock options outstanding as of December 31, 2007 is 75,000 for Mr. Lombardi, 25,000 for each of Messrs. Churay and Higbee and 25,000 for Mr. Shaner. On March 3, 2008, Mr. Shaner executed a Waiver and Cancellation of Stock Option Award, which cancelled the award of options to purchase 25,000 shares of our common stock granted to him on November 7, 2007. Prior to cancellation, Mr. Shaner did not exercise any of these options.

Changes in Director Compensation for 2008

During 2007, the Compensation Committee implemented a director compensation policy which will be effective for 2008. Under the new policy, our non-employee directors will receive an annual retainer of $20,000. Any non-employee director joining our board in the course of the year will receive a prorated portion of the annual retainer. The chairmen of our Nominating and Governance Committee, Compensation Committee and Audit Committees will receive an additional annual retainer of $5,500, $5,500 and $10,000, respectively. Each non-employee director will be paid a cash fee of $1,500 for every board meeting attended and a cash fee of $850 for every committee meeting attended.

On the first board meeting following the annual meeting of our stockholders, we will grant options to purchase 25,000 shares of our common stock to each of our non-employee directors. These option awards will vest ratably over a three year period, commencing on the one-year anniversary of the date of grant.

As has been the practice since our initial public offering in July 2007, our Chairman, Mr. Shaner, will not receive any compensation from the Company for acting in such capacity. He will receive the same cash and equity-based compensation paid generally to our other non-employee directors.

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

The following table sets forth our common stock ownership for each of our directors, for each of our named executive officers, all of our directors and executive officers as a group, and each of our known 5% stockholders. Beneficial ownership is determined in accordance with SEC rules and regulations. Unless otherwise indicated and subject to community property laws where applicable, we believe that each of the stockholders named in the table below has sole voting and investment power with respect to the shares indicated as beneficially owned. Unless otherwise indicated, all stockholders set forth below have the same principal business address as the Company. Information in the table is as of March 29, 2008, unless otherwise indicated.

Name of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent(1)
Lance T. Shaner	12,595,762(2)	40.9
Benjamin W. Hulburt	1,381,717(3)	4.5
Thomas F. Shields	1,063,124(4)	3.5
Thomas C. Stabley	588,538(5)	1.9
Christopher K. Hulburt	571,075(6)	1.9
Jack S. Shawver	476,230(7)	1.5
Daniel J. Churay	—	*
John W. Higbee	—	*
John A. Lombardi	—	*
Goldman Sachs Asset Management, L.P.(8)	2,085,230	6.8
All executive officers and directors as a group (9 total)	**16,676,446**	**54.2**

* Less than 1%.

(1) Based on 30,794,702 shares of our common stock outstanding as of March 28, 2008.

(2) Represents (a) 10,436,269 shares held directly and (b) 1,314,903 shares owned by Shaner Family Partner Limited Partnership for which Mr. Shaner disclaims beneficial ownership, 472,209 shares owned by Rexguard, LLC for which Mr. Shaner disclaims beneficial ownership, 276,927 shares owned by Shaner & Hulburt Capital Partners Limited Partnership for which Mr. Shaner disclaims beneficial ownership, and 95,454 shares owned by The Lance T. Shaner Irrevocable Grandchildren's Trust II for which Mr. Shaner disclaims beneficial ownership.

(3) Represents (a) 1,379,876 shares held directly and (b) 1,841 shares held in a personal individual retirement account.

(4) Represents (a) 738,899 shares held directly and (b) 324,225 shares held by Douglas Oil & Gas, Inc., of which Mr. Shields is the President. Mr. Shields disclaims beneficial ownership of the shares held by Douglas Oil & Gas, Inc. Mr. Shields resigned from the Company effective February 29, 2008. Shareholding information is based upon information provided to the Company by Mr. Shields on March 29, 2008.

(5) Represents (a) 583,672 shares held directly and (b) 4,866 shares held in a personal individual retirement account.

(6) Represents 571,075 shares held directly.

(7) Represents 476,230 shares held directly.

(8) The address of Goldman Sachs Asset Management, L.P. is 32 Old Slip, New York, New York 10005. Goldman Sachs Asset Management, L.P. exercises sole voting power over 1,910,137 and sole dispositive power over all 2,085,230 of these shares. This information is based on a Schedule 13G filed by Goldman Sachs Asset Management, L.P. with the Securities and Exchange Commission on February 1, 2008.

Securities Authorized for Issuance Under Equity Compensation Plans

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants, and rights	Weighted-average exercise price of outstanding options, warrants, and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	815,000	$9.90	2,264,470(1)
Equity compensation plans not approved by security holders	0	0	0
Total	815,000	$9.90	2,264,470

(1) Represents shares of common stock available for issuance under our 2007 Long-Term Incentive Plan.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Company Policies Regarding Related Party Transactions

We do not have a written approval policy for transactions between the Company and our executive officers and directors, but these transactions are subject to the limitations on conflicts of interest and related-party transactions found in our Code of Business Conduct and Ethics (the "Code"). Under the Code, executive officers and directors endeavor to avoid any actual, potential or apparent conflict of interest between their personal and professional relationships. Any proposed related transactions, however, may be approved in accordance with both applicable law and applicable NASDAQ rules. For approval, a committee of independent directors of the Board of Directors must approve any transaction that exceeds $5,000 or otherwise requires disclosure in the Company's proxy statement pursuant to Item 404 of Regulation S-K.

Certain Relationships with Our Chairman

We lease an office building consisting of approximately 5,270 square feet of office space from Shaner Brothers, LLC, a Pennsylvania limited liability company ("Shaner Brothers"), which is owned by Lance T. Shaner, our Chairman, and Shaner Family Partners Limited Partnership, a Pennsylvania limited partnership controlled by Mr. Shaner. This office space, which we currently use as our headquarters, is located at 1975 Waddle Road, State College, Pennsylvania. We currently lease this office space pursuant to a written lease agreement between Rex Operating and Shaner Brothers effective as of September 1, 2006. The lease agreement provides for an initial term of three years and expires on August 31, 2009. The lease agreement requires the payment of rent in the amount of $7,908 per month, subject to adjustment on each anniversary date of the lease in accordance with the percentage of increase in the Consumer Price Index for the U.S. for Urban Consumers (CPI-U) for the preceding year (the "CPI Adjustment"). The monthly rent is also subject to adjustment in the form of additional monthly rent which is calculated annually and equal to the percentage of increase of Shaner Brothers' costs for taxes, insurance premiums and operating expenses for the previous year (the "Additional Monthly Rent"). The annual monthly rent adjustment resulting from the CPI Adjustment and Additional Monthly Rent may not in the aggregate exceed a three percent increase over the prior lease year. Under the terms of the lease, we are responsible for certain costs relating to the interior construction of the building and the payment of all utilities, cleaning expenses, maintenance and other related costs and expenses of the building resulting from our operation, use and occupancy of the premises. Following the expiration of the initial term, we may renew the lease for up to three one-year extensions upon written notice to Shaner Brothers at least 120 days, but no more than six months, prior to the expiration of the current term. We believe the terms of this lease are comparable to terms that could be obtained at an arms' length basis in the State College, Pennsylvania area for leases of similar office space.

On December 26, 2007, we entered into a new office lease agreement with an unrelated third party to lease approximately 16,000 square feet of office space to serve as our new headquarters in State College, Pennsylvania. We expect to occupy our new office space in May 2008. Shaner Brothers is searching for a new tenant to lease our current office space; however, as of March 28, 2008, Shaner Brothers has not entered into a new lease agreement with any party. Under our current lease agreement with Shaner Brothers, we will be required to continue to pay all amounts owing under the lease agreement until expiration of its term or until such time as Shaner Brothers agrees to terminate the lease and rent the office space to another party. When the office space is leased by another party, we believe that Shaner Brothers will agree to terminate our current office lease agreement and release us from any further obligations under the agreement.

On September 1, 2006, Shaner Brothers loaned $264,656 to Rex Operating to fund its expenses relating to the construction of the interior portions of its headquarters office building. This loan was evidenced by an unsecured promissory note dated September 1, 2006. The promissory note provided for the payment of interest on the unpaid principal sum at a rate of 7% per annum. The loan was required to be repaid in 60 consecutive equal monthly installments of principal and interest in the amount of $5,240.50. The promissory note matured on September 1, 2011, but could be prepaid in whole or in part at anytime, without premium or penalty. We repaid this loan in its entirety on July 30, 2007 with proceeds from our initial public offering.

Prior to April 2007, we received certain administrative services (such as information technology, human resources, benefit plan administration, payroll and tax services) from Shaner Solutions Limited Partnership, a Delaware limited partnership controlled by Mr. Shaner ("Shaner Solutions"), pursuant to an oral month-to-month agreement providing for a monthly fee of $15,000, plus reimbursement for reasonable out-of-pocket expenses. On April 10, 2007, we terminated our oral month-to-month administrative services agreement with Shaner Solutions. For the period covering January 1, 2007 to April 10, 2007 we paid Shaner Solutions $53,000 in relation to these services. For the years ended December 31, 2006 and 2005, we paid $180,000 and $195,000, respectively, to Shaner Solutions in relation to these services. We believe that the amounts charged by Shaner Solutions were comparable to rates obtainable at an arm's-length basis in the State College, Pennsylvania area for similar services.

In conjunction with the termination of our oral agreement with Shaner Solutions, we entered into an IT Consultation and Support Services Agreement, a Service Provider Agreement and a Tax Return Engagement Letter Agreement with Shaner Hotel Group Limited Partnership, a Delaware limited partnership controlled by Lance T. Shaner ("Shaner Hotel"). Pursuant to the IT Consultation and Support Services Agreement, Shaner Hotel agreed to provide us with telecommunication, computer system and network administration, and information technology consultation services. Fees for the services provided under this agreement range from $55.00 to $125.00 per hour based upon the type and level of service provided, plus reimbursement for reasonable out-of-pocket expenses. The agreement continues until it is terminated by either party upon 90 days advance written notice. Pursuant to the Service Provider Agreement, Shaner Hotel agreed to provide us with certain clerical and administrative support services in connection with the management and administration of our 401(k) retirement plan, payroll and employee health and welfare benefit plans. Under the agreement, we pay a fee of $95.00 per hour for any services performed by Shaner Hotel's benefits manager and a fee of $55.00 per hour for services provided by other members of Shaner Hotel's benefits department, plus reimbursement for reasonable out-of-pocket expenses. The term of the Service Provider Agreement is one year, however, either party may terminate the agreement upon 90 days advance written notice. Pursuant to the Tax Return Engagement Letter Agreement, Shaner Hotel agreed to provide us with certain tax planning and tax return preparation services. Fees for the services provided under this agreement range from $100.00 to $155.00 per hour based upon the tax expertise of the particular service provider, plus reimbursement for reasonable out-of-pocket expenses. The agreement continues until it is terminated by either party upon 90 days advance written notice. For the period covering April 10, 2007 to December 31, 2007, we paid $66,000 to Shaner Hotels in relation to these services. We believe that the amounts charged by Shaner Hotel are comparable to rates obtainable at an arm's-length basis in the State College, Pennsylvania area for similar services.

We currently have an oral month-to-month agreement with Charlie Brown Air Corp., a New York corporation owned by Mr. Shaner ("Charlie Brown"), regarding the use of two airplanes owned by Charlie Brown. Under our agreement with Charlie Brown, we pay a monthly fee for the right to use the airplanes equal to our percentage (based upon the total number of hours of use of the airplanes by us) of the monthly fixed costs for the airplanes, plus a variable per hour flight rate of $1,350 per hour. The total monthly fixed costs for the airplane is currently approximately $26,000 per month. For the year ended December 31, 2007 we paid Charlie Brown $188,000 in relation to these services. We believe the terms of this agreement are comparable to terms that could be obtained at an arms' length basis in the State College, Pennsylvania area for similar private aircraft services.

On June 21, 2007, we obtained a 24.75% limited partnership interest in Charlie Brown II Limited Partnership, a Delaware limited partnership ("Charlie Brown II"), and a 25% membership interest in its general partner, L&B Air LLC, a Delaware limited liability company ("L&B Air"). Charlie Brown II has ordered and agreed to purchase an Eclipse 500 Airplane for approximately $1,700,000. The airplane was scheduled to be delivered from the manufacturer to Charlie Brown II in January of 2008, but delivery of the airplane has been delayed to June 2008. Shaner Hotel Group Limited Partnership, a Delaware limited partnership controlled by Mr. Shaner ("Shaner Hotel Group"), owns a 24.65% limited partnership interest in Charlie Brown II and a 25% membership interest in L&B Air, and Charlie Brown, an entity owned and controlled by Mr. Shaner, owns a .1% membership interest in Charlie Brown II. The remaining 49.50% limited partnership interest in Charlie Brown II and 50% interest in L&B Air is owned by an unrelated third party. On June 21, 2007, we made capital contributions to Charlie Brown II and L&B Air in the amount of $49,500 and $500, respectively. To fund these capital contributions, we borrowed $50,000 from our Chairman, Lance T. Shaner. This loan was evidenced by a promissory note dated June 21, 2007 and bore interest at the rate of 7% per annum. The promissory note was payable upon the demand of Mr. Shaner and could be prepaid in whole or in part without penalty. We believe that the terms of this loan were comparable to terms that could be obtained at an arms' length basis from unrelated lenders. We repaid this loan in its entirety on July 30, 2007 with proceeds from our initial public offering.

On June 21, 2007, Charlie Brown II and Charlie Brown entered into a First Amended and Restated Aircraft Joint Ownership and Management Agreement. Pursuant to this agreement, Charlie Brown agreed to provide certain aircraft management services, such as routine and scheduled maintenance, flight crew training, cleaning, inspections and flight operations and scheduling of the aircraft. In addition, Charlie Brown agreed to provide a flight crew for the operation of the aircraft and storage space in its hanger for storage of the aircraft. In exchange for these services, Charlie Brown II agreed to pay its proportionate share of Charlie Brown's fixed costs, including crew, hanger and insurance costs, and a per hour flight charge to be determined by Charlie Brown consistent with current local market rates charged by similar flight operation companies.

The business affairs of Charlie Brown II are managed by its general partner, L&B Air. L&B Air is managed by three managers, appointed by each of its three members. We have designated Benjamin W. Hulburt, our Chief Executive Officer, as the manager representing our membership interest. Actions of L&B Air must be approved by a majority of the interest percentages of the managers. Each manager votes in matters before the company in accordance the membership interest percentage of the member that appointed the manager. Certain events, such as the sale by a member of its interest, the merger or consolidation of L&B Air or Charlie Brown II, the filing of bankruptcy, or the sale of the airplane owned by Charlie Brown II, require the consent of all managers. The consent of all limited partners of Charlie Brown II is required before the partnership may change or terminate the management agreement with Charlie Brown, incur any indebtedness, sell substantially all of the partnership's assets or sell the airplane owned by the partnership. In the event that the limited partners are unable to unanimously agree upon any of these matters within 10 days of the proposal of any such matter, an "impasse" may be declared, and the airplane will be sold by the partnership.

On June 21, 2007, Charlie Brown II borrowed $1,530,000 from Graystone Bank. Proceeds from this loan were used to reimburse Lance T. Shaner and an unrelated third party for a deposit they paid on behalf of Charlie Brown II in connection with the purchase of the Eclipse 500 airplane. The loan matures on June 21, 2017 and bears interest at a rate of LIBOR plus 2.5%. The loan requires payments of interest only for the first three months of the loan. Thereafter, Charlie Brown II is required to make monthly payments of principal and interest utilizing

an amortization period of 180 months. The loan to Charlie Brown II was guaranteed by Lance T. Shaner and the unrelated third party.

At December 31, 2006, there was a working capital loan payable to Mr. Shaner, our Chairman, in the amount of $1,820,000 from PennTex Illinois, one of the Predecessor Companies. At the time this loan was made, Mr. Shaner was the sole stockholder of PennTex Illinois. The loan was non-interest-bearing and was payable upon the demand of Mr. Shaner. In January 2007, the outstanding amount was satisfied through the conversion of $820,000 into an equity capital contribution into such Predecessor Company and the repayment of $1,000,000 to Mr. Shaner.

Mr. Shaner is our Chairman and a significant stockholder of the Company. Mr. Shaner's ownership and association with Shaner Brothers, Shaner Solutions, Shaner Hotel, Charlie Brown, Charlie Brown II and us could create a conflict of interest between the interests of those entities and Mr. Shaner's duties and obligations to us. The compensation for these arrangements and the purchase, leasing, financing, management and other arrangements between us and any Shaner affiliates may not be (to the extent permissible under applicable laws and regulations) a result of arm's-length negotiations, and the relationships created by virtue of these arrangements may be subject to certain conflicts of interest. Our board of directors (with Mr. Shaner abstaining) performs a quarterly review of these contractual agreements, whether oral or written, and may continue, extend, amend or terminate any of these agreements.

Director Independence

As part of the Company's corporate governance practices, and in accordance with NASDAQ rules, the Board has established a policy requiring a majority of the members of the Board to be independent. For a director to be independent, the board must determine, among other things, that the director does not have any direct or indirect material relationship with the company. The guidelines for determining director independence are set forth in our Corporate Governance Policy, which conforms to the independence requirements of the NASDAQ corporate governance standards. Applying these independence standards, the board has determined that Daniel J. Churay, John W. Higbee and John A. Lombardi are all independent directors. In addition, as each of Messrs. Churay, Higbee and Lombardi are members of the Audit Committee of our board, the board has determined that each of them is "independent" as defined by Rule 10A-3 of the Securities Exchange Act of 1934.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Audit and Audit-Related Fees

Our independent registered public accounting firm for 2007 and 2006 was Malin Bergquist & Company, LLP. The fees billed to us by Malin Bergquist & Company, LLP are shown in the table below ($ in thousands).

	Year Ended December 31, 2007	Year Ended December 31, 2006
Audit fees(1)	$406	$253
Audit related fees(2)	87	1
Tax fees	—	—
All other fees	—	—
	$493	$254

(1) Audit fees consist of fees billed for professional services rendered for the audit of our annual financial statements, reviews of the financial statements included in our quarterly reports and services that are normally provided in connection with statutory and regulatory filings.

(2) Audit-related fees shown in the table above consist of fees billed for assurance and related services that are reasonably related to the performance of the audit or review of our consolidated financial statements and are not reported under "Audit Fees." These services include accounting consultations in connection with acquisitions, attest services that are not required by statute or regulation, and consultations concerning financial accounting and reporting standards.

Pre-Approval Policies and Procedures

The Audit Committee's policy is to pre-approve all audit and non-audit services provided to the Company by its independent registered public accounting firm (except for items exempt from pre-approval requirements under applicable laws and rules).

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

(a)(1) Financial Statements

(a)(2) Financial Statement Schedules

All other schedules are omitted because they are not applicable, not required, or because the required information is included in the financial statements or related notes.

(a)(3) Exhibits.

Exhibit Number	Exhibit Title
2.1	Agreement and Plan of Merger among New Albany-Indiana, LLC, Rex Energy III LLC, Rex Energy I, LLC and Rex Energy Corporation (incorporated by reference to Exhibit 2.1 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on July 6, 2007).
2.2	Agreement and Plan of Merger among Douglas Oil & Gas Limited Partnership, Douglas Westmoreland Limited Partnership, Midland Exploration Limited Partnership, Rex Energy Limited Partnership, Rex Energy II Limited Partnership, Rex Energy II Alpha Limited Partnership, Rex Energy Royalties Limited Partnership, Rex Energy I, LLC and Rex Energy Corporation (incorporated by reference to Exhibit 2.2 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on July 6, 2007).
2.3	Contribution Agreement among Lance T. Shaner, Benjamin W. Hulburt, Michael J. Carlson, Jack Shawver, Thomas F. Shields, Thomas C. Stabley, Christopher K. Hulburt, PennTex Energy Inc. and Rex Energy Corporation (incorporated by reference to Exhibit 2.3 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on July 6, 2007).
3.1	Certificate of Incorporation of Rex Energy Corporation (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on April 27, 2007).
3.2	Amendment to Certificate of Incorporation of Rex Energy Corporation (incorporated by reference to Exhibit 3.2 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on April 27, 2007).
3.3	Amended and Restated Bylaws of Rex Energy Corporation (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on April 27, 2007).

Exhibit Number	Exhibit Title
4.1	Form of Specimen Common Stock Certificate of Rex Energy Corporation (incorporated by reference to Exhibit 4.1 to Amendment No. 1 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on June 11, 2007).
4.2	Form of Registration Rights Agreement (incorporated by reference to Exhibit 4.1 to Amendment No. 1 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on June 11, 2007).
10.1+	Rex Energy Corporation 2007 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to the registrant's Registration Statement on Form S-1/A filed on June 11, 2007).
10.2+	Amended and Restated Employment Agreement by and between Jack S. Shawver and Rex Energy Operating Corp. dated May 18, 2006 (incorporated by reference to Exhibit 10.4 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on April 27, 2007).
10.3	Consent Decree (incorporated by reference to Exhibit 10.5 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on April 27, 2007).
10.4	Independent Director Agreement with John A. Lombardi dated April 1, 2007 (incorporated by reference to Exhibit 10.6 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on April 27, 2007).
10.5	Service Provider Agreement, dated April 1, 2007, between Shaner Hotel Group Limited Partnership and Rex Energy Operating Corp. (incorporated by reference to Exhibit 10.7 to Amendment No. 1 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on June 11, 2007).
10.6	Service Level Agreement, dated April 13, 2007, between Shaner Hotel Group Limited Partnership and Rex Energy Operating Corp. (incorporated by reference to Exhibit 10.8 to Amendment No. 1 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on June 11, 2007).
10.7	Letter Agreement, dated April 13, 2007, between Shaner Hotel Group Limited Partnership and Rex Energy Operating Corp. (incorporated by reference to Exhibit 10.9 to Amendment No. 1 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on June 11, 2007).
10.8	Lease Agreement, dated September 1, 2006, between Shaner Brothers, LLC and Rex Energy Operating Corp. (incorporated by reference to Exhibit 10.10 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on July 6, 2007).
10.9	Promissory Note, dated September 1, 2006, by Rex Energy Operating Corp. to Shaner Brothers, LLC. (incorporated by reference to Exhibit 10.11 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on July 6, 2007).
10.10	Summary of oral month-to-month administrative services agreement between Shaner Solutions Limited Partnership and Rex Energy Operating Corp. (incorporated by reference to Exhibit 10.12 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on July 6, 2007).
10.11	Summary of oral month-to-month agreement regarding use of airplane between Charlie Brown Air Corp. and Rex Energy Operating Corp. (incorporated by reference to Exhibit 10.13 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on July 6, 2007).
10.12	Summary of oral working capital loan agreement between Lance T. Shaner and PennTex Resources Illinois, Inc. (incorporated by reference to Exhibit 10.14 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on July 6, 2007).

Exhibit Number	Exhibit Title
10.13	Amended and Restated Limited Liability Company Agreement, dated June 21, 2007, of L&B Air LLC (incorporated by reference to Exhibit 10.15 to Amendment No. 2 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on July 6, 2007).
10.14	Amended and Restated Limited Partnership Agreement, dated June 21, 2007, of Charlie Brown II Limited Partnership (incorporated by reference to Exhibit 10.16 to Amendment No. 2 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on July 6, 2007).
10.15	Promissory Note, dated June 21, 2007, by Rex Energy Operating Corp. to Lance T. Shaner (incorporated by reference to Exhibit 10.17 to Amendment No. 2 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on July 6, 2007).
10.16	First Amended and Restated Aircraft Joint Ownership and Management Agreement, dated June 21, 2007, between Charlie Brown Air Corp. and Charlie Brown II Limited Partnership (incorporated by reference to Exhibit 10.18 to Amendment No. 2 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on July 6, 2007).
10.17+	Employment Agreement by and between Benjamin W. Hulburt and Rex Energy Operating Corp. dated August 1, 2007 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K as filed with the SEC on August 7, 2007).
10.18+	Employment Agreement by and between Thomas F. Shields and Rex Energy Operating Corp. dated August 1, 2007 (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K as filed with the SEC on August 7, 2007).
10.19+	Employment Agreement by and between Thomas C. Stabley and Rex Energy Operating Corp. dated August 1, 2007 (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K as filed with the SEC on August 7, 2007).
10.20+	Employment Agreement by and between Christopher K. Hulburt and Rex Energy Operating Corp. dated August 1, 2007 (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K as filed with the SEC on August 7, 2007).
10.21+	Employment Agreement by and between William L. Ottaviani and Rex Energy Operating Corp. dated August 8, 2007 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K as filed with the SEC on August 14, 2007).
10.22	Credit Agreement, dated as of September 28, 2007, among Rex Energy Corporation, as Borrower, KeyBank National Association, as Administrative Agent, BNP Paribas, as Syndication Agent, Sovereign Bank, as Documentation Agent and The Lenders Party Thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K as filed with the SEC on October 3, 2007).
10.23	Guaranty and Collateral Agreement, dated as of September 28, 2007, made by Rex Energy Corporation and each of the other grantors (as defined therein) in favor of KeyBank National Association, as Administrative Agent (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K as filed with the SEC on October 3, 2007).
10.24	Independent Director Agreement by and between Rex Energy Corporation and Daniel J. Churay effective as of October 19, 2007 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on October 19, 2007).
10.25	Independent Director Agreement by and between Rex Energy Corporation and John W. Higbee effective as of October 17, 2007 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on October 19, 2007).
10.26	Rex Energy Corporation Director Compensation Plan Effective As of January 1, 2008 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on December 11, 2007).

Exhibit Number	Exhibit Title
10.27+	Amended and Restated Separation Agreement dated February 29, 2008 between Rex Energy Operating Corp. and Thomas F. Shields (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on March 3, 2008).
10.28*+	Form of Nonqualified Stock Option Award Agreement for employee common stock option awards under Rex Energy 2007 Long-Term Incentive Plan.
10.29*	Form of Nonqualified Stock Option Award Agreement for non-employee director common stock option awards under Rex Energy 2007 Long-Term Incentive Plan.
10.30*+	Form of Stock Appreciation Right Award Agreement under Rex Energy 2007 Long-Term Incentive Plan.
21.1*	Subsidiaries of the Registrant.
23.1*	Consent of Malin, Bergquist & Company, LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
23.3*	Consent of Surtek, Inc.
31.1*	Certification of Chief Executive Officer (Principal Executive Officer) pursuant to Section 302 of the Sarbanes-Oxley Act.
31.2*	Certification of Chief Financial Officer (Principal Financial and Principal Accounting Officer) pursuant to Section 302 of the Sarbanes-Oxley Act.
32.1*	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act.

* Filed herewith.

\+ Indicates management contract or compensation plan or arrangement.

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a description of the meanings of some of the oil and gas industry terms used in this report:

Basin. A large natural depression on the earth's surface in which sediments accumulate.

Bbl. One stock tank barrel, of 42 U.S. gallons liquid volume, of crude oil.

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

Bopd. Barrels of oil per day.

Btu or British Thermal Unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The installation of permanent equipment for the production of oil or gas.

Development or Developmental well. A well drilled within the proved boundaries of an oil or gas reservoir with the intention of completing the stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses, taxes and the royalty burden.

Exploitation. A drilling or other project which may target proven or unproven reserves (such as probable or possible reserves), but generally is expected to have lower risk.

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

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

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

Horizontal drilling. A drilling operation in which a portion of the well is drilled horizontally within a productive or potentially productive formation. This operation usually yields a well which has the ability to produce higher volumes than a vertical well drilled in the same formation.

Injection well or Injection. A well which is used to place liquids or gases into the producing zone during secondary/tertiary recovery operations to assist in maintaining reservoir pressure and enhancing recoveries from the field.

Lease operating expenses. The expenses of lifting oil or gas from a producing formation to the surface, and the transportation and marketing thereof, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, ad valorem taxes and other expenses incidental to production, but excluding lease acquisition or drilling or completion expenses.

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

MBOE. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet of natural gas.

Mcfd. One thousand cubic feet of natural gas per day.

MMBbls. One million barrels of oil or other liquid hydrocarbons.

MMBOE. One million barrels of oil equivalent.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of gas.

MMcfe. One million cubic feet equivalent, determined using the ratio of six Mcf of gas to one Bbl of oil, condensate or gas liquids.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or wells, as the case may be.

NYMEX. New York Mercantile Exchange.

PV-10 or present value of estimated future cash flows. An estimate of the present value of the estimated future cash flows from proved oil and gas reserves at a date indicated after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of federal income taxes. The estimated future cash flows are discounted at an annual rate of 10%, in accordance with the Securities and Exchange Commission's practice, to determine their *"present value."* The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Estimates of future cash flows are made using oil and gas prices and operating costs at the date indicated and held constant for the life of the reserves.

Primary recovery. The period of production in which oil and natural gas is produced from its reservoir through the wellbore without enhanced recovery technologies, such as water floods or ASP floods.

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 exceed production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed non-producing reserves or *PDNP.* Proved developed reserves expected to be recovered from zones behind casing in existing wells.

Proved developed producing reserves or *PDP.* Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production 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 oil, gas and 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 reserves or *PUD*. 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 addition of production from another interval or formation in an existing wellbore.

Reserve life index. This index is calculated by dividing year-end proved reserves by the average production during the past year to estimate the number of years of remaining production.

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

Secondary recovery. An artificial method or process used to restore or increase production from a reservoir after the primary production by the natural producing mechanism and reservoir pressure has experienced partial depletion. Gas injection and waterflooding are examples of this technique.

Tertiary recovery. The third stage of hydrocarbon production during which sophisticated techniques that alter the original properties of the oil are used. Chemical flooding (including ASP flooding), miscible displacement and thermal flooding are examples of this technique.

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 or gas regardless of whether or not such acreage contains proved reserves.

Waterflooding. A secondary recovery operation in which water is injected into the producing formation in order to maintain reservoir pressure and force oil toward and into the producing wells.

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

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

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.

Dated: March 31, 2008

REX ENERGY CORPORATION

By: /s/ BENJAMIN W. HULBURT

Benjamin W. Hulburt
President and Chief Executive Officer

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

/s/ LANCE T. SHANER **Lance T. Shaner**	Chairman of the Board	March 31, 2008
/s/ BENJAMIN W. HULBURT **Benjamin W. Hulburt**	President, Chief Executive Officer and Director (Principal Executive Officer and Director)	March 31, 2008
/s/ THOMAS C. STABLEY **Thomas C. Stabley**	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 31, 2008
/s/ DANIEL J. CHURAY **Daniel J. Churay**	Director	March 31, 2008
/s/ JOHN W. HIGBEE **John W. Higbee**	Director	March 31, 2008
/s/ JOHN A. LOMBARDI **John A. Lombardi**	Director	March 31, 2008

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CORPORATE INFORMATION

From left to right: Larry Gorski (VP Human Resources), Matthew Ford (VP Controller), Benjamin Hulburt (Pres. & CEO), William Ottaviani (Exec. VP & COO), Christopher Hulburt (Exec. VP & General Counsel), Thomas Stabley (Exec. VP & CFO)

COMPANY EXECUTIVES

Benjamin W. Hulburt
President and Chief Executive Officer

Thomas C. Stabley
Executive Vice President and Chief Financial Officer

William L. Ottaviani
Executive Vice President and Chief Operating Officer

Christopher K. Hulburt
Executive Vice President, Secretary and General Counsel

BOARD OF DIRECTORS

Lance T. Shaner
Chairman

Benjamin W. Hulburt
Director, President and Chief Executive Officer

Daniel J. Churay
Director and Chairman of Compensation Committee

John A. Lombardi
Director and Chairman of Audit Committee

John W. Higbee
Director and Chairman of Nominating and Governance Committee

INDEPENDENT AUDITORS

Malin, Bergquist & Company, LLP
2402 West 8th Street
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Telephone (814) 454-4008

TRANSFER AGENT

Computershare Investor Services
P.O. Box 43036
Providence, Rhode Island 02940-3036
Telephone (866) 299-4221

CORPORATE HEADQUARTERS

1975 Waddle Road
State College, Pennsylvania 16803
Telephone (814) 278-7267

INVESTOR RELATIONS

Joseph DeSimone
jdesimone@rexenergycorp.com
Telephone (814) 278-7267
www.rexenergy.com

STOCK INFORMATION/MARKET DATA (12/31/07)

30.8 million shares outstanding
0.8 million options outstanding
52-week high-low $13.01-$7.99
Rex Energy Corporation is traded on the NASDAQ Stock Exchange under the ticker symbol "REXX"

ANNUAL MEETING

June 10, 2008
Toftrees Golf Resort & Conference Center
One Country Club Lane
State College, Pennsylvania 16803

The following table sets forth, for the periods indicated, the range of the daily high and low sale prices for our common stock as reported by NASDAQ.

2007	High	Low
Third quarter	$10.50	$7.50
Fourth quarter	$11.99	$8.00

PERFORMANCE GRAPH