RAM ENERGY RESOURCES INC
Form 424B1
February 08, 2007
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Filed pursuant to Rule 424(b)(1)
SEC File No. 333-138922

PROSPECTUS

7,500,000 Shares

RAM Energy Resources, Inc.

Common Stock

We are offering 7,500,000 shares of our common stock. Our shares of common stock are quoted on the Nasdaq Capital Market under the symbol RAME .

You should read the risk factors beginning on page 12 of this prospectus to learn about certain factors you should consider before buying shares of our common stock.

PRICE $4.00 PER SHARE

	Per Share	Total
Public Offering Price	$ 4.00	$ 30,000,000
Underwriting Discount	$ 0.26	$ 1,950,000
Net proceeds to RAM Energy Resources, Inc. (1)	$ 3.74	$ 28,050,000

(1) Before deducting expenses of the offering payable by us estimated at $675,000.

One of our principal stockholders, Danish Knights, A Limited Partnership, has granted an over-allotment option to the underwriters. Under this option, the underwriters may elect to purchase a maximum of 1,125,000 additional shares from the selling stockholder at the public offering price less underwriting discount within 30 days following the date of this prospectus to cover over-allotments. We will pay all expenses, other than underwriting discounts payable by the selling stockholder, associated with the offering. We will not receive any proceeds from the sale of the shares by the selling stockholder.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is accurate or complete. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the shares of common stock to investors on or about February 13, 2007.

RBC CAPITAL MARKETS

JEFFERIES & COMPANY

JOHNSON RICE & COMPANY L.L.C.

SANDERS MORRIS HARRIS

FERRIS, BAKER WATTS INCORPORATED

GILFORD SECURITIES INCORPORATED

February 7, 2007

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ABOUT THIS PROSPECTUS

You should rely only on the information contained in this prospectus. We have not authorized anyone to provide you with different information. We are not making an offer of these securities in any state where the offer is not permitted. You should not assume that the information contained in this prospectus is accurate as of any date other than the date on the front cover of this prospectus.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this prospectus, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this prospectus, the words could, believe, anticipate, intend, estimate, expect, project and similar expressions are intended to id forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- technology;
- financial strategy;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- the amount, nature and timing of capital expenditures;
- drilling of wells;
- competition and government regulations;
- marketing of oil and natural gas;
- property acquisitions;
- costs of developing our properties and conducting other operations;
- general economic conditions;

- uncertainty regarding our future operating results; and

- plans, objectives, expectations and intentions contained in this prospectus that are not historical.

All forward-looking statements speak only as of the date of this prospectus, and we do not intend to update any of these forward-looking statements to reflect changes in events or circumstances that arise after the date of this prospectus. You should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this prospectus are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under *Risk Factors* and *Management s Discussion and Analysis of Financial Condition and Results of Operations* and elsewhere in this prospectus. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf. The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications or other published independent sources. Some data are also based on our good faith estimates. Although we believe these third-party sources are reliable, we have not independently verified the information and cannot guarantee its accuracy and completeness.

PROSPECTUS SUMMARY

This summary highlights information contained in other parts of our prospectus. Because it is a summary, it does not contain all information that you should consider before investing in our shares. You should read the entire prospectus carefully, including Risk Factors, our financial statements and the notes thereto. We have included definitions of technical terms important to an understanding of our business under Glossary of Oil and Natural Gas Terms.

Unless the context otherwise requires, all references in this prospectus to RAM Energy Resources, our, us, and we refer to RAM Energy Resources, Inc. (formerly known as Tremisis Energy Acquisition Corporation) and its subsidiaries, as a combined entity. All references in this prospectus to RAM Energy refer to RAM Energy, Inc., our wholly owned subsidiary. Unless the context otherwise requires, the information contained in this prospectus gives effect to the May 8, 2006 consummation of the merger of RAM Energy Acquisition, Inc., our wholly owned subsidiary, with and into RAM Energy, and the change of our name from Tremisis Energy Acquisition Corporation to RAM Energy Resources, Inc., which transactions are collectively called the merger. See Prospectus Summary Recent Events for a discussion of the merger. As used in this prospectus, EBITDA refers to net income before interest expense, amortization, depreciation, accretion, income taxes, gain on early extinguishment of debt, gain on sale of oil and natural gas properties, share-based compensation, extraordinary gains or losses, the cumulative effects of changes in accounting principles and unrealized gains or losses on derivatives.

RAM Energy Resources, Inc.

We are an independent oil and natural gas company engaged in the acquisition, development, exploitation, exploration and production of oil and natural gas properties, primarily in Texas, Louisiana and Oklahoma. Our producing properties are located in highly prolific basins with long histories of oil and natural gas operations. We have been active in these core areas since our inception in 1987 and have grown through a balanced strategy of acquisitions and development and exploratory drilling. We have completed over 20 acquisitions of producing oil and natural gas properties and related assets for an aggregate purchase price approximating $400 million. Through December 31, 2006, we have drilled or participated in the drilling of 561 oil and natural gas wells, 93% of which were successfully completed and produced hydrocarbons in commercial quantities. Our management team has extensive technical and operating expertise in all areas of our geographic focus.

Our oil and natural gas assets are characterized by a combination of conventional and unconventional reserves and prospects. We have conventional reserves and production in four main onshore locations:

- Electra/Burkburnett, Wichita and Wilbarger Counties, Texas;
- Boonsville, Jack and Wise Counties, Texas;
- Vinegarone, Val Verde County, Texas; and
- Egan, Acadia Parish, Louisiana.

We have unconventional reserves and production in our Barnett Shale play located in Jack and Wise Counties, Texas, where we own interests in approximately 27,700 gross (6,800 net) acres.

In addition, we have positioned ourselves for participation in two emerging resource plays in southwest Texas. We have an exploratory play targeting the Barnett and Woodford Shale formations where we own interests in approximately 84,000 gross (6,600 net) acres. We also have an exploratory play targeting the Wolfcamp formation where we are actively acquiring acreage and have accumulated leases and options covering over 15,000 gross and net acres.

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At December 31, 2005, our estimated net proved reserves were 18.8 MMBoe, of which approximately 60% were crude oil, 30% were natural gas, and 10% were natural gas liquids, or NGLs. The PV-10 Value of our proved reserves was approximately $345.5 million based on prices we were receiving as of December 31, 2005, which were $58.63 per Bbl of oil, $35.89 per Bbl of NGLs and $9.14 per Mcf of natural gas. At December 31, 2005, our proved developed reserves comprised 70% of our total proved reserves, and the estimated reserve life for our total proved reserves was approximately 15 years.

We own interests in approximately 2,900 wells and are the operator of leases upon which approximately 1,900 of these wells are located. The PV-10 Value attributable to our interests in the properties we operate represented approximately 86% of our aggregate PV-10 Value as of December 31, 2005. We also own a drilling rig, various gathering systems, a natural gas processing plant, service rigs and a supply company that service our properties.

From January 1, 1997 through December 31, 2005, our reserve replacement percentage, through discoveries, extensions, revisions and acquisitions, but excluding divestitures, was 344%. Since January 1, 1997, our historical average finding cost from all sources, exclusive of divestitures, has been $6.27 per Boe. During the twelve months ended December 31, 2006, we drilled or participated in the drilling of 92 wells on our oil and natural gas properties, 80 of which were successfully completed as producing wells, four of which were dry holes and eight of which were either drilling or waiting to be completed at the end of that period. For the twelve months ended September 30, 2006 we generated EBITDA of $33.8 million from production averaging 3,740 Boe per day. For more information regarding our EBITDA, including a reconciliation to our net income (loss), see *Selected Consolidated Financial Data.*

Our Business Strategy and Strengths

Our primary objective is to enhance stockholder value by increasing our net asset value, net reserves and cash flow per share through acquisitions, development, exploitation, exploration and divestiture of oil and natural gas properties. We intend to follow a balanced risk strategy by allocating capital expenditures in a combination of lower risk development and exploitation activities and higher potential exploration prospects. We intend to pursue acquisitions during periods of attractive acquisition values and emphasize development of our reserves during periods of higher acquisition values. Key elements of our business strategy include the following:

Concentrate on Our Existing Core Areas. We intend to focus a significant portion of our growth efforts in our existing core areas. Our oil and natural gas properties in our core areas are characterized by long reserve lives and production histories in multiple oil and natural gas horizons. We believe our focus on and experience in our core areas may expose us to acquisition opportunities which may not be available to the entire industry.

Accelerate Our North Texas Barnett Shale Development. Due to the high degree of commercial success in the north Texas Barnett Shale by the oil and natural gas industry, we plan to use proceeds of this offering to significantly accelerate drilling in our north Texas Barnett Shale properties. We have over 325 potential horizontal well locations on our properties. We have drilled nine gross (3.4 net) wells to date with a 100% success rate on our north Texas Barnett Shale properties and plan on drilling a minimum of four gross (2.1 net) wells to a maximum of seven gross (2.8 net) wells during 2007.

Complete Selective Acquisitions and Divestitures. We seek to acquire producing oil and natural gas properties, primarily in our core areas. Our experienced senior management team has developed our acquisition criteria designed to increase reserves, production and cash flow per share on an accretive basis. We will seek acquisitions of producing properties that will provide us with opportunities for

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reserve additions and increased cash flow through operating improvements, production enhancement and additional development and exploratory prospect generation opportunities. In addition, from time to time, we may engage in strategic divestitures when we believe our capital may be redeployed to higher return projects.

Develop and Exploit Existing Oil and Natural Gas Properties. We have historically increased stockholder value by fully developing or exploiting our acquired and discovered properties until we determine that it is no longer economically attractive to do so. As of December 31, 2006, we have identified 161 proved development and extension drilling projects and 166 recompletion/workover projects on our existing properties and wells.

Increase Emphasis on Exploration Activity. We are committed to increasing our emphasis on exploration activities within the context of our balanced risk objectives. We will continue to acquire, review and analyze 3-D seismic data to generate exploratory prospects. Our exploration efforts utilize available geological and geophysical technologies to reduce our exploration and drilling risks and, therefore, maximize our probability of success.

We believe that the following strengths complement our business strategy:

Inventory of Growth Opportunities in the North Texas Barnett Shale. We believe we have a significant inventory of growth opportunities beyond our proved reserve base. We have over 325 potential drilling locations within the north Texas Barnett Shale. We believe that our inventory of potential drilling locations should provide us the opportunity to grow organically for the foreseeable future without having to depend upon acquisitions of properties. Based on current cost estimates, we have approximately $250 million of potential future capital expenditures for the full development of our north Texas Barnett Shale acreage.

Management Experience and Technical Expertise. Our key management and technical staff possess an average of 26 years of experience in the oil and natural gas industry, a substantial portion of which has been focused on operations in our core areas. We believe that the knowledge, experience and expertise of our staff will continue to support our efforts to enhance stockholder value.

Balanced Oil and Natural Gas Production. At year-end 2005, approximately 60% of our estimated proved reserves were oil, 30% were natural gas and 10% were NGLs. We believe this balanced commodity mix, combined with our prudent use of derivative contracts, will provide sufficient diversification of sources of cash flow and will lessen the risk of significant and sudden decreases in revenue from localized or short-term commodity price movements.

Operating Efficiency and Control. We currently operate wells that represent 86% of our aggregate PV-10 Value at December 31, 2005. Our high degree of operating control allows us to control capital allocation and expenses and the timing of additional development and exploitation of our producing properties.

Drilling Expertise and Success. Our management and technical staff have a long history of successfully drilling oil and natural gas wells. Through December 31, 2006, we have drilled or participated in the drilling of 561 oil and natural gas wells with a 93% success rate. We expect to continue to grow by utilizing our drilling expertise and developing and finding additional reserves, although our success rate may decline as we drill more exploratory wells.

Ownership and Control of Service and Supply Assets. We own and control service and supply assets, including a drilling rig, service rigs, a supply company, gathering systems and other related assets. We believe that ownership and use of these assets for our own account provides us with a significant

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competitive advantage with respect to availability, lead-time and cost of these services. For calendar year 2007, approximately 75% of our projected capital expenditures will be in areas serviced by these assets.

Insider Ownership. After giving effect to the completion of this offering, our directors, executive officers and our two principal stockholders will own approximately 63% of our outstanding shares, providing a strong alignment of interest between management, the board of directors and our outside stockholders.

Balance Sheet Flexibility. After giving effect to the completion of this offering and application of the net proceeds as described in this prospectus, we will have significant liquidity for pursuing acquisitions, accelerating our development and exploratory activities and taking advantage of opportunities as they arise.

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Principal Producing Properties

The following is a summary of our oil and natural gas reserve information with respect to our principal properties as of December 31, 2005 and with respect to our producing wells, drilling locations and net acreage as of December 31, 2006:

	Electra/ Burkburnett	Boonsville	Egan	Barnett Shale	Vinegarone
Proved reserves (Mboe)	9,802	3,011	1,651	408	1,110
Percent proved developed	61%	69%	100%	83%	31%
Percent oil	97%	6%	11%	2%	
PV-10 Value (in thousands) (1)	$ 182,920	$ 43,403	$ 38,424	$ 10,410	$ 21,480
Gross producing wells:					
Operated by RAM Energy	536	87	10	2	
Operated by others		1		7	8
Proved drilling locations	134	20		4	3
Potential unproven drilling locations				325	
Total net acres	12,190	7,313	3,740	6,800	1,830

(1) The PV-10 Value of our proved reserves as of December 31, 2005 was calculated using unescalated prices of $58.63 per Bbl of oil, $35.89 per Bbl of NGLs, and $9.14 per Mcf of natural gas, which were the prices we were receiving as of December 31, 2005. The prices at which we sell natural gas are determined on the first day of each month for the entire month.

Principal Exploration Projects

The following is a summary of our principal exploration projects as of December 31, 2006, both of which are located in southwest Texas:

Name	Objective	Net Acres
Wolfcamp	Shale Gas Canyon Sands	15,000
Barnett/Woodford	Shale Gas	6,600

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Recent Events

Tremisis Merger. Prior to May 8, 2006, our corporate name was Tremisis Energy Acquisition Corporation, or Tremisis. On May 8, 2006, Tremisis acquired RAM Energy, Inc. through the merger of its recently formed, wholly owned subsidiary into RAM Energy, Inc. The merger was accomplished pursuant to the terms of an Agreement and Plan of Merger dated October 20, 2005, as amended, which is referred to as the merger agreement, among Tremisis, its acquisition subsidiary, RAM Energy, Inc. and the stockholders of RAM Energy, Inc. Upon completion of the merger, RAM Energy, Inc. became Tremisis wholly owned subsidiary and Tremisis changed its name from Tremisis Energy Acquisition Corporation to RAM Energy Resources, Inc.

Upon consummation of the merger, the stockholders of RAM Energy, Inc. received an aggregate of 25,600,000 shares of Tremisis common stock and $30.0 million of cash. Prior to consummation of the merger, and as permitted by the merger agreement, on April 6, 2006, RAM Energy, Inc. redeemed a portion of its outstanding stock for an aggregate consideration of $10.0 million.

The merger was accounted for as a reverse acquisition. RAM Energy, Inc. has been treated as the acquiring company and the continuing reporting entity for accounting purposes. Upon completion of the merger, the assets and liabilities of Tremisis were recorded at their fair value, which is considered to approximate historical cost, and added to those of RAM Energy, Inc. Because Tremisis had no active business operations prior to consummation of the merger, the merger was accounted for as a recapitalization of RAM Energy, Inc.

Acquisition of Properties. Effective September 1, 2006, we acquired 447,000 Boe of proved reserves and associated gathering assets in a field located in close proximity to our existing north Texas properties. Current production from the acquired properties is from the Bend Conglomerate. The acquired properties also included undeveloped deep rights, including the Barnett Shale formation. The purchase price was $4.6 million, or $9.84 per Boe of estimated proved reserves. The proved reserve mix in the acquired properties is 72% natural gas and 28% oil.

Stock Transactions. On September 22, 2006, we repurchased 739,175 shares of our common stock from an unaffiliated party in a negotiated transaction at a purchase price of $4.295 per share. On November 10, 2006, we approved the grant of restricted stock awards under our 2006 Long-Term Incentive Plan for an aggregate of 646,805 shares of our common stock to 22 of our employees, including two of our vice presidents, one of whom received an award of 75,100 shares, and the other who received an award of 69,170 shares. We will incur compensation expense of approximately $3.3 million, which will be recognized ratably through 2011, in connection with our November 10, 2006 restricted stock issuances.

Fourth Quarter Operations. During the quarter ended December 31, 2006, we drilled or participated in the drilling of 23 gross (22 net) development wells of which 22 gross (21.8 net) were completed as commercial wells. Also during the fourth quarter of 2006, we participated in the drilling of four gross (2.2 net) exploratory wells, two gross (2.0 net) of which were in our Wolfcamp prospect. All four exploratory wells were in various stages of completion at year end. At December 31, 2006, we owned interests in 2,205 gross (1,484 net) producing wells, of which 1,938 gross (1,362 net) wells were oil wells, and 267 gross (122 net) wells were natural gas wells. At that date, we owned, or held options to acquire, developed acreage consisting of 104,199 gross (38,248 net) leasehold acres and undeveloped acreage of 131,883 gross (32,228 net) leasehold acres.

Our non-acquisition related capital expenditures during the fourth quarter of 2006 aggregated $5.7 million, of which $4.3 million was allocated to development and exploitation activities, and

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$1.4 million was allocated to exploration activities. Our total non-acquisition capital expenditures for 2006, were approximately $23.4 million, compared to our 2006 capital expenditure budget of $24.3 million. In addition, we expended $4.6 million in our acquisition of 447,000 Boe of proved reserves in the third quarter of 2006.

Barnett Shale Activities. During the first quarter of 2007, we proposed to EOG Resources, Inc. the drilling of two horizontal Barnett Shale wells on our jointly-owned acreage in North Texas. EOG has elected to participate in and operate the first proposed well. Under the terms of our April 2004 agreement, EOG has until early March to make a participation election with respect to the second well. Our share of the estimated cost of drilling and completing each well is approximately $700,000. In addition, Devon Energy Corporation recently proposed the drilling of the seventh Barnett Shale well under our Participation Agreement with Devon. We intend to participate in the proposed well. Our share of the estimated cost of the Devon well is expected to be approximately $1.0 million. For further information regarding our agreements with EOG and Devon, see *Business and Properties Principal Properties.*

Risks Related to Our Strategy

Prospective investors should carefully consider the matters we discuss under the caption *Risk Factors,* as well as the other information in this prospectus, including that the market for attractive opportunities to acquire properties with proved undeveloped reserves may not be available; our reserve estimates may not be accurate; our results will be affected by the volatile nature of oil and natural gas prices and we may experience delays in obtaining drilling rigs and shortages of equipment. One or more of these matters could negatively affect our ability to successfully implement our business strategy.

Our Executive Offices

Our principal executive offices are located at 5100 East Skelly Drive, Suite 650, Tulsa, Oklahoma 74135. Our telephone number is (918) 663-2800.

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The Offering

Common stock offered by us	7,500,000 Shares
Option (1)	One of our principal stockholders, Danish Knights, A Limited Partnership, has granted the underwriters a 30-day option to purchase up to an aggregate of 1,125,000 additional shares of common stock.
Common stock outstanding after the offering (2)	40,939,530 Shares
Use of Proceeds	We intend to use the net proceeds from this offering to provide additional working capital for general corporate purposes, including acquisition, development, exploitation and exploration of oil and natural gas properties and reduction of indebtedness.
Nasdaq Capital Market symbol	RAME

(1) Danish Knights is a family limited partnership formed by Dr. William W. Talley II, a founder and former chairman of RAM Energy, Inc. Dr. Talley passed away in 2005. No partner of Danish Knights is a director or officer of RAM Energy Resources, Inc.

(2) The shares of common stock outstanding after this offering do not include approximately 12,650,000 shares issuable upon the exercise of outstanding warrants at an exercise price of $5.00 per share and 825,000 shares of our common stock issuable upon the exercise of currently exercisable options to purchase 275,000 units at an exercise price of $9.90 per unit, each unit consisting of one share of our common stock and two warrants, each warrant to purchase one share of our common stock at an exercise price of $6.25 per share. Such warrants, when issued, will be immediately exercisable. The shares of common stock to be outstanding after this offering do not include shares of our common stock that we will issue upon the exercise of options or other awards that may be granted under our 2006 Long-Term Incentive Plan. We have remaining a maximum of 1,423,195 shares of common stock reserved for issuance upon the exercise of options that may be granted and pursuant to awards that may be made under our 2006 Long-Term Incentive Plan.

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SUMMARY CONSOLIDATED FINANCIAL INFORMATION AND OTHER DATA

We are providing the following summary consolidated financial information and other data to assist you in your analysis of our financial condition and results of operations. We acquired RAM Energy effective May 8, 2006, by the merger of our recently formed, wholly owned subsidiary with and into RAM Energy, which transaction we refer to as the merger. See *Prospectus Summary Recent Events* for a discussion of the merger. For accounting and financial reporting purposes, the merger was accounted for under the purchase method of accounting as a reverse acquisition and, in substance, as a capital transaction, because Tremisis had no active business operations prior to consummation of the merger. Accordingly, for accounting and financial reporting purposes, the merger was treated as the equivalent of RAM Energy issuing stock for the net monetary assets of Tremisis, accompanied by a recapitalization. The net monetary assets of Tremisis have been stated at their fair value, essentially equivalent to historical costs, with no goodwill or other intangible assets recorded. The accumulated deficit of RAM Energy has been carried forward. Operations prior to the merger are those of RAM Energy.

The consolidated balance sheet data as of December 31, 2004 and 2005 and the consolidated statement of operations data for the years ended December 31, 2003, 2004 and 2005 are derived from RAM Energy s consolidated financial statements audited by UHY Mann Frankfort Stein & Lipp CPAs, LLP, independent registered public accountants, and are included elsewhere in this prospectus. The consolidated balance sheet data as of December 31, 2003 and the consolidated statement of operations data for the year ended December 31, 2002 are derived from RAM Energy s consolidated financial statements audited by UHY Mann Frankfort Stein & Lipp CPAs, LLP, independent registered public accountants, which are not included in this prospectus. The consolidated balance sheet data of RAM Energy as of December 31, 2001 and 2002 and the consolidated statement of operations data for the year ended December 31, 2001 are derived from RAM Energy s unaudited consolidated financial statements, which are not included in this prospectus.

The summary consolidated financial information and other data presented below is only a summary and should be read in conjunction with the historical consolidated financial statements of each of RAM Energy and Tremisis, and the related notes, *Management s Discussion and Analysis of Financial Condition and Results of Operations* and *Business and Properties*. The historical results included below and elsewhere in this prospectus may not be indicative of our future performance. RAM Energy s financial position and results of operations for 2003, 2004 and 2005 may not be comparative to other periods as a result of certain divestitures and acquisitions, as more fully described in RAM Energy s financial statements included elsewhere in this prospectus.

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Summary Consolidated Financial Information

(in thousands)

Statement of Operations Data	Year Ended December 31, 2001	2002	2003	2004	2005 (1)	Nine Months Ended September 30, 2005 (1) (unaudited)	2006 (1) (unaudited)
Oil and natural gas sales	$ 25,404	$ 10,166	$ 20,053	$ 17,975	$ 66,243	$ 48,140	$ 53,050
Production taxes	2,755	1,044	1,408	1,263	3,320	2,460	2,527
Production expenses	5,975	3,023	3,527	3,600	16,099	11,453	13,222
General and administrative expenses	4,061	5,858	6,331	6,601	8,610	6,285	6,351
Depreciation and amortization	9,766	2,947	4,098	3,273	12,972	9,213	10,019
Interest expense	(14,410)	(8,963)	(4,871)	(5,035)	(12,539)	(8,728)	(12,975)
Operating income (loss)	4,839	(2,689)	4,608	14,844	13,888	2,882	19,889
Income (loss) from continuing operations	3,751	13,256	(491)	6,076	543	(3,624)	3,990
Statement of Cash Flow Data							
Cash provided by (used in):							
Operating activities	$ 2,240	$ (14,842)	$ 5,774	$ 1,793	$ 18,359	$ 10,616	$ 25,294
Investing activities	44,520	(46)	7,422	(64,852)	(12,554)	(9,877)	(18,710)
Financing activities	(27,803)	(3,731)	(12,333)	62,116	(6,910)	(161)	938
Other Data							
Capital expenditures (2)	$ 11,349	$ 6,700	$ 5,258	$ 102,719	$ 13,526	$ 11,078	$ 21,529
EBITDA (3)	14,709	473	8,670	18,153	33,747	27,208	26,888

Balance Sheet Data	As of December 31, 2001	2002	2003	2004	2005 (1)	As of September 30, 2005 (1) (unaudited)	2006 (1) (unaudited)
Total assets	$ 98,322	$ 62,192	$ 45,908	$ 140,324	$ 143,276	$ 140,708	$ 158,157
Total debt	91,400	56,267	46,057	117,344	112,846	117,301	131,696
Stockholders deficit	(20,347)	(16,842)	(19,653)	(19,912)	(20,769)	(24,436)	(29,043)

(1) We acquired WG Energy Holdings, Inc. in December 2004.

(2) Includes costs of acquisitions.

(3) EBITDA for the twelve months ended September 30, 2006 was $33.8 million. For more information regarding our EBITDA, including a reconciliation to our net income (loss), see *Selected Consolidated Financial Data.*

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Summary Reserve Data

	As of December 31,		
	2003	2004	2005
Proved reserves:			
Oil (MBbls)	2,322	10,667	11,199
Natural gas (MMcf)	34,567	38,195	34,234
Natural gas liquids (MBbls)		2,087	1,891
Total (MBoe)	8,083	19,120	18,796
Percent proved developed	80.7%	67.9%	70.2%
Percent oil	28.7%	55.8%	59.6%
Estimated future net revenues before income taxes (in thousands)	$ 160,456	$ 434,028	$ 601,111
PV-10 Value (in thousands)	$ 104,570	$ 236,201	$ 345,501
Prices used to calculate PV-10 Value:			
Oil (per Bbl)	$ 29.25	$ 40.25	$ 58.63
Natural gas (per Mcf)	6.17	6.02	9.14
Natural gas liquids (per Bbl)		27.56	35.89

Summary Operating Data

The following tables present certain information with respect to oil and natural gas production, prices and costs attributable to our oil and natural gas properties for the three years ended December 31, 2005 and the nine months ended September 30, 2006. We acquired WG Energy in December 2004. Our operating data for 2004 includes operations of WG Energy from the date of acquisition.

	Year ended December 31,			Nine months Ended September 30,
	2003	2004	2005	2006
Production volumes:				
Oil (MBbls)	277	178	787	592
Natural gas liquids (MBbls)	5	12	170	103
Natural gas (MMcf)	2,334	1,928	2,681	1,761
Total (MBoe)	671	511	1,405	989
Average realized prices (after effect of derivative contracts):				
Oil (per Bbl)	$ 29.47	$ 33.15	$ 52.35	$ 57.46
Natural gas liquids (per Bbl)	16.94	26.41	36.33	41.89
Natural gas (Per Mcf)	5.06	5.73	5.57	6.12
Per Boe	29.89	33.77	44.38	49.68
Expenses (per Boe):				
Oil and natural gas production taxes	$ 2.10	$ 2.47	$ 2.36	$ 2.56
Oil and natural gas production expenses	5.26	7.04	11.46	13.38
Amortization of full cost pool	5.64	5.89	8.93	9.63
General and administrative	9.44	12.90	6.13	6.42

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RISK FACTORS

You should carefully consider the following risk factors, together with all of the other information included in this prospectus.

The volatility of oil and natural gas prices greatly affects our profitability.

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves, and may result in write-downs of the carrying values of our oil and natural gas properties as a result of our use of the full cost accounting method.

Wide fluctuations in oil and natural gas prices may result from relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and other factors that are beyond our control, including:

- worldwide and domestic supplies of oil and natural gas;
- weather conditions;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the availability of drilling rigs and completion equipment;
- the availability of pipeline capacity;
- the price and volume of foreign imports;
- domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil-producing regions; and
- the overall economic environment.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. Declines in oil and natural gas prices would not only reduce revenue, but could reduce the amount of oil and natural gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves.

Our success depends on acquiring or finding additional reserves.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are produced, except to the extent that we conduct successful exploration or development activities or acquire

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properties containing proved reserves, or both. To increase reserves and production, we must commence exploratory drilling, undertake other replacement activities or utilize third parties to accomplish these activities. There can be no assurance, however, that we will have sufficient resources to undertake these actions, that our exploratory projects or other replacement activities will result in significant additional reserves or that we will succeed in drilling productive wells at low finding and development costs. Furthermore, although our revenues may increase if prevailing oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

In accordance with customary industry practice, we rely in part on independent third party service providers to provide most of the services necessary to drill new wells, including drilling rigs and related equipment and services, horizontal drilling equipment and services, trucking services, tubular goods, fracing and completion services and production equipment. The oil and natural gas industry has experienced significant volatility in cost for these services in recent years and this trend is expected to continue into the future. Any future cost increases could significantly increase our development costs and decrease the return possible from drilling and development activities, and possibly render the development of certain proved undeveloped reserves uneconomical.

Estimates of oil and natural gas reserves are uncertain and may vary substantially from actual production.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of expenditures, including many factors beyond our control. Petroleum engineering is not an exact science. Information relating to our proved oil and natural gas reserves is based upon engineering estimates. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, future site restoration and abandonment costs, the assumed effects of regulations by governmental agencies and assumptions concerning future oil and natural gas prices, future operating costs, severance and excise taxes, capital expenditures and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net cash flows expected therefrom prepared by different engineers or by the same engineers at different times may vary substantially. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

We expect to obtain a substantial portion of our funds for the drilling and development of our oil and natural gas properties through borrowings. If such funds were not available to us, or if the terms upon which such funds would be available to us were unfavorable, the further development of our oil and natural gas reserves, and our financial condition and results of operations, could be adversely affected.

We expect to fund a substantial portion of our future leasehold acquisitions and our drilling and development operations with borrowed funds. To the extent such funds are not available to us at all, or if the terms under which such funds would be available to us would be unfavorable, the further development of our oil and natural gas reserves could be adversely impacted and we could be limited as to the amount of additional leasehold acreage we could acquire. In such events, we may be unable to replace our reserves of oil and natural gas which, subsequently, could adversely affect our financial condition and results of operations.

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Operating hazards and uninsured risks may result in substantial losses.

Our operations are subject to all of the hazards and operating risks inherent in drilling for, and the production of, oil and natural gas, including the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards such as oil spills, gas leaks, ruptures or discharges of toxic gases. The occurrence of any of these events could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks. There can be no assurance that any insurance will be adequate to cover any losses or liabilities. We cannot predict the continued availability of insurance, or its availability at premium levels that justify its purchase. In addition, we may be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities would not be covered by our insurance.

Several of our subsidiaries are defendants in a pending class action suit alleging the underpayment of oil and natural gas royalties. If our subsidiaries were ultimately determined to be liable, the amount of the judgment could adversely affect our financial condition.

Several of our subsidiaries are named defendants in a pending class action suit in which the plaintiffs are seeking monetary damages for our alleged underpayment of oil and natural gas royalties. The plaintiffs seek unspecified damages for alleged breach of contract, alleged tortious breach of implied covenants and alleged breach of fiduciary duty, together with punitive damages and other equitable relief. The aggregate dollar amount of the damages sought by the plaintiffs has not yet been calculated. If the amount of any damages ultimately awarded to the plaintiffs were material, it could adversely affect our financial condition. For a further discussion of this litigation, please see *Business and Properties Legal Proceedings* appearing elsewhere in this prospectus.

Our operations are subject to various governmental regulations that require compliance that can be burdensome and expensive.

Our operations are subject to various federal, state and local governmental regulations that may be changed from time to time in response to economic and political conditions. Matters subject to regulation include discharge from drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity to conserve supplies of oil and natural gas. In addition, the production, handling, storage, transportation and disposal of oil and natural gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state and local laws and regulations primarily relating to protection of human health and the environment. These laws and regulations have continually imposed increasingly strict requirements for water and air pollution control and solid waste management, and compliance with these laws may cause delays in the additional drilling and development of our properties. Significant expenditures may be required to comply with governmental laws and regulations applicable to us. We believe the trend of more expansive and stricter environmental legislation and regulations will continue. While historically we have not experienced any material adverse effect from regulatory delays, there can be no assurance that such delays will not occur in the future.

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Our method of accounting for investments in oil and natural gas properties may result in impairment of asset value, which could affect our stockholder equity and net profit or loss.

We use the full cost method of accounting for our investment in oil and natural gas properties. Under the full cost method of accounting, all costs of acquisition, exploration and development of oil and natural gas reserves are capitalized into a full cost pool. Capitalized costs in the pool are amortized and charged to operations using the units-of-production method based on the ratio of current production to total proved oil and natural gas reserves. To the extent that such capitalized costs, net of amortization, exceed the present value of our proved oil and natural gas reserves (using a 10% discount rate) at any reporting date, such excess costs are charged to operations. Although we have never incurred a write down of the value of oil and natural gas properties, if a writedown is incurred, it is not reversible at a later date, even if the present value of our proved oil and natural gas reserves increases as a result of an increase in oil or natural gas prices.

Properties that we acquire may not produce as projected, and we may be unable to identify liabilities associated with the properties or obtain protection from sellers against them.

As part of our business strategy, we continually seek acquisitions of oil and natural gas properties. Our most recent significant acquisition, which closed in December 2004, was our purchase of WG Energy Holdings, Inc. The successful acquisition of oil and natural gas properties requires assessment of many factors, which are inherently inexact and may be inaccurate, including the following:

- future oil and natural gas prices;
- the amount of recoverable reserves;
- future operating costs;
- future development costs;
- failure of titles to properties;
- costs and timing of plugging and abandoning wells; and
- potential environmental and other liabilities.

Our assessment will not necessarily reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. With respect to properties on which there is current production, we may not inspect every well location, every potential well location, or pipeline in the course of our due diligence. Inspections may not reveal structural and environmental problems such as pipeline corrosion or groundwater contamination. We may not be able to obtain or recover on contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

We face extensive competition in our industry.

We operate in a highly competitive environment. We compete with major and independent oil and natural gas companies, many of whom have financial and other resources substantially in excess of those available to us. These competitors may be better positioned to take advantage of industry opportunities and to withstand changes affecting the industry, such as fluctuations in oil and natural gas prices and production, the availability of alternative energy sources and the application of government regulation.

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Risk Related to Our Common Stock

Purchasers in this offering will experience immediate and substantial dilution in the book value of their investment.

Purchasers of our common stock in this offering will experience an immediate, substantial dilution of $4.12 per share of common stock because the price per share of common stock in this offering is substantially higher than the net tangible book value of each share of common stock outstanding immediately after this offering. Our net tangible book value as of September 30, 2006 on a pro forma basis after giving effect to this offering and the application of proceeds from such offering is approximately $(5.0) million, or $(0.12) per share of common stock. In addition, purchasers may experience further dilution from issuances of shares of our common stock in the future. See *Dilution.*

We do not currently pay dividends on our common stock and do not anticipate doing so in the future.

Prior to consummation of the merger, RAM Energy regularly paid cash dividends to its stockholders. We intend to retain any future earnings to fund our operations. Therefore, we do not anticipate paying any cash dividends on our common stock in the foreseeable future.

A substantial number of shares of our common stock will be available for sale in the future, which may increase the volume of common stock available for sale in the open market and may cause a decline in the market price of our common stock.

Sales of a substantial number of shares of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline. We issued 25,600,000 shares of our common stock in connection with our acquisition of RAM Energy. These shares were not registered under the Securities Act of 1933, and their resale is restricted. All of such shares are subject to a lock-up agreement and cannot be sold publicly until the expiration of the restricted periods set out in the lock-up agreement (a maximum of one year after May 8, 2006) and under Rule 144 promulgated under the Securities Act of 1933. However, the holders of such shares have certain registration rights and will be able to sell their shares in the public market prior to such times if registration is effected. The presence of this additional number of shares of common stock eligible for trading in the public market may have an adverse effect on the market price of our common stock.

Voting control by our executive officers, directors and other affiliates may limit your ability to influence the outcome of director elections and other matters requiring stockholder approval.

Persons who beneficially own approximately 80% (65% after giving effect to the completion of this offering) of our outstanding common stock are parties to a voting agreement. These persons have agreed to vote for each other s designees to our board of directors through director elections in 2008. Accordingly, they will be able to control the election of directors and, therefore, our policies and direction during the term of the voting agreement. This concentration of voting power could have the effect of delaying or preventing a change in our control or discouraging a potential acquirer from attempting to obtain control of us, which in turn could have a material adverse effect on the market price of our common stock or prevent our stockholders from realizing a premium over the market price for their shares of common stock.

You may experience dilution of your ownership interests due to the future issuance of additional shares of our common stock, which could have an adverse effect on our stock price.

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 currently authorized to issue 100.0 million shares of common stock and one million shares of preferred stock with such designations, preferences and rights as determined by our board of directors. As of the date of this prospectus, we had outstanding 33,439,530 shares of common stock, warrants to purchase 12,650,000 shares of our common stock and an agreement to issue 825,000 shares of our common stock upon the exercise of currently exercisable options to purchase 275,000 units, each unit consisting of one share of common stock and two warrants, each warrant to purchase one share of our common stock. These warrants when issued will be immediately exercisable. In addition, we have reserved an additional 1,423,195 shares for future issuance to employees as restricted stock or stock option awards pursuant to our 2006 Long-Term Incentive Plan. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock. 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 issuances 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.

Certain provisions of Delaware law, our certificate of incorporation and bylaws could hinder, delay or prevent a change in control of our company, which could adversely affect the price of our common stock.

Certain provisions of Delaware law, our certificate of incorporation and bylaws could have the effect of discouraging, delaying or preventing transactions that involve an actual or threatened change in control of our company. Delaware law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. In addition, our certificate of incorporation and bylaws include the following provisions:

Classified Board of Directors. Our board of directors is divided into three classes with staggered terms of office of three years each. The classification and staggered terms of office of our directors make it more difficult for a third party to gain control of our board of directors. At least two annual meetings of stockholders, instead of one, generally would be required to effect a change in a majority of the board of directors.

Removal of Directors. Under Delaware law, directors that serve on a classified board, such as our directors, may be removed only for cause by the affirmative vote of the holders of at least a majority of the voting power of the outstanding shares of our capital stock.

Number of Directors, Board Vacancies, Term of Office. Our certificate of incorporation and our bylaws provide that only the board of directors may set the number of directors. We have elected to be subject to certain provisions of Delaware law which vest in the board of directors the exclusive right, by the affirmative vote of a majority of the remaining directors, to fill vacancies on the board even if the remaining directors do not constitute a quorum. When effective, these provisions of Delaware law, which are applicable even if other provisions of Delaware law or the charter or bylaws provide to the contrary, also provide that any director elected to fill a vacancy shall hold office for the remainder of the full term of the class of directors in which the vacancy occurred, rather than the next annual meeting of stockholders as would otherwise be the case, and until his or her successor is elected and qualifies.

Advance Notice Provisions for Stockholder Nominations and Proposals. Our bylaws require advance written notice for stockholders to nominate persons for election as directors at, or to bring other business before, any meeting of stockholders. This bylaw provision limits the ability of stockholders to make nominations of persons for election as directors or to introduce other proposals unless we are notified in a timely manner prior to the meeting.

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Amending the Bylaws. Our certificate of incorporation permits our board of directors to adopt, alter or repeal any provision of the bylaws or to make new bylaws. Our certificate of incorporation also provides that our bylaws may be amended by the affirmative vote of the holders of at least 80% of the voting power of the outstanding shares of our capital stock.

Authorized but Unissued Shares. Under our certificate of incorporation, our board of directors has authority to cause the issuance of preferred stock from time to time in one or more series and to establish the terms, preferences and rights of any such series of preferred stock, all without approval of our stockholders. Nothing in our certificate of incorporation precludes future issuances without stockholder approval of the authorized but unissued shares of our common stock.

We could issue additional preferred stock which could be entitled to dividend, liquidation and other special rights and preferences not shared by holders of our common stock or which could have anti-takeover effects.

We are authorized to issue up to one million shares of preferred stock, which shares may be issued from time to time in one or more series as our board of directors, by resolution or resolutions, may from time to time determine. The voting powers, preferences and relative, participating, optional and other special rights, and the qualifications, limitations or restrictions thereof, if any, of each such series of our preferred stock may differ from those of any and all other series of preferred stock at any time outstanding, and, subject to certain limitations of the our certificate of incorporation and Delaware law, our board of directors may fix or alter, by resolution or resolutions, the designation, number, voting powers, preferences and relative, participating, optional and other special rights, and qualifications, limitations and restrictions thereof, of each such series of our preferred stock. The issuance of any such preferred stock could materially adversely affect the rights of holders of our common stock and, therefore, could reduce the value of our common stock.

In addition, specific rights granted to future holders of preferred stock could be used to restrict our ability to merge with, or sell our assets to, a third party. The ability of our board of directors to issue preferred stock could discourage, delay or prevent a takeover of us, thereby preserving our control by the current stockholders.

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USE OF PROCEEDS

Our net proceeds from the sale of the shares of common stock that we are offering will be approximately $27.4 million. Net proceeds are what we expect to receive after paying the underwriting discounts and the other estimated expenses of this offering. We will not receive any proceeds from the sale of shares by the selling stockholder upon exercise, if any, of the over-allotment option by the underwriters.

We intend to use all of the net proceeds of this offering to provide additional working capital for general corporate purposes including acquisitions, development, exploitation and exploration of oil and natural gas properties and reduction of indebtedness.

We have outstanding $28.4 million of our 11 1/2% senior notes that mature February 15, 2008. Our revolving credit facility matures in 2010 and our term facility matures in 2011. At December 31, 2006, the interest rate on borrowings outstanding under our revolving credit facility was 7.4% per annum and under our term facility was 11.1% per annum. Borrowings under our credit facility have been used primarily for acquisition and development of our oil and natural gas properties, working capital and general corporate purposes. Please read *Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources* for additional information about our 11 1/2% senior notes and our credit facility.

Until we use the proceeds from this offering, we will invest the funds in short-term, investment grade, interest-bearing securities.

DIVIDEND POLICY

Prior to the consummation of the merger, RAM Energy regularly paid cash dividends to its stockholders. We have paid no dividends since the date of the merger. We currently intend to retain all of our earnings to finance our operations, repay indebtedness and fund our future growth. We do not expect to pay any dividends on our common stock for the foreseeable future. In addition, covenants contained in the instruments governing our credit facility limit our ability to pay dividends on our common stock. See *Management s Discussion and Analysis of Financial Condition and Results of Operation Liquidity and Capital Resources.*

DILUTION

The net tangible book value of our issued and outstanding common stock at September 30, 2006, was $(32.4) million, or $(0.99) per share, based on the number of shares of our common stock outstanding at September 30, 2006. After giving effect, as of that date, to our sale of 7,500,000 shares of common stock at a price of $4.00 per share and the receipt by us of approximately $27.4 million in net proceeds from this offering, the pro forma net tangible book value would have been $(5.0) million, or $(0.12) per share of common stock. This amount represents an immediate increase in net tangible book value per share of $0.87 to existing stockholders and immediate dilution of $4.12 in net tangible book value per share to persons purchasing shares of common stock at a price of $4.00 per share. The following table illustrates this dilution on a per share basis:

Per share offering price	$ 4.00
Net tangible book value per share at September 30, 2006 (1)	$ (0.99)
Increase attributable to sale of shares of common stock (2)	$ 0.87
Pro forma net tangible book value per share after the offering (2)	$ (0.12)
Dilution in net tangible book value per share to new investors (2) (3)	$ 4.12

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(1) Net tangible book value per share of common stock is determined by dividing our tangible net worth (total tangible assets ($154.8 million) less total liabilities ($187.2 million)) at September 30, 2006 by the number of shares of common stock outstanding.

(2) After deducting estimated expenses of this offering payable by us.

(3) Dilution is determined by subtracting net tangible book value per share of common stock after the offering from the offering price per share.

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CAPITALIZATION

The following table shows our capitalization on September 30, 2006 and our capitalization on September 30, 2006, as adjusted to give effect to the completion of this offering at an offering price of $4.00 per share and the use of the net proceeds as described under Use of Proceeds.

	Actual	As Adjusted
	(in thousands)	
Cash and cash equivalents	$ 7,592	$ 34,967
Current portion of long-term debt	$ 194	$ 194
Long-term debt, less current portion	$ 131,502	$ 131,502
Stockholders equity (deficit):		
Preferred stock, $0.0001 par value, 1,000,000 shares authorized; no shares issued or outstanding	$	$
Common stock, $0.0001 par value, 100,000,000 shares authorized; 32,792,725 shares issued and outstanding, actual; 40,292,725 shares issued and outstanding, as adjusted	3	4
Additional paid-in capital	2,218	29,592
Treasury stock	(3,768)	(3,768)
Accumulated deficit	(27,496)	(27,496)
Total stockholders (deficit)	$ (29,043)	$ (1,668)
Total capitalization	$ 102,459	$ 129,834

The shares of common stock issued and outstanding do not include approximately 12,650,000 shares reserved for issuance upon the exercise of outstanding warrants and 825,000 shares of our common stock issuable upon the exercise of currently exercisable options to purchase 275,000 units, each unit consisting of one share of our common stock and warrants to purchase two shares of our common stock; an aggregate of 1,423,195 shares remaining reserved for issuance upon the exercise of options that may be granted by us or awards that may be made under our 2006 Long-Term Incentive Plan, and 646,805 shares of common stock issued as restricted stock awards on November 10, 2006 under our 2006 Long-Term Incentive Plan.

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SELECTED CONSOLIDATED FINANCIAL DATA

We are providing the following selected financial information to assist you in your analysis of our financial condition and results of operations. We acquired RAM Energy effective May 8, 2006, by the merger of our recently formed, wholly owned subsidiary with and into RAM Energy. See *Prospectus Summary Recent Events* for a description of the merger. For accounting and financial reporting purposes, the merger was accounted for under the purchase method of accounting as a reverse acquisition and, in substance, as a capital transaction, because Tremisis had no active business operations prior to consummation of the merger. Accordingly, for accounting and financial reporting purposes, the merger was treated as the equivalent of RAM Energy issuing stock for the net monetary assets of Tremisis accompanied by a recapitalization. The net monetary assets of Tremisis have been stated at their fair value, essentially equivalent to historical costs, with no goodwill or other intangible assets recorded. The accumulated deficit of RAM Energy has been carried forward. Operations prior to the merger are those of RAM Energy.

Our consolidated balance sheet data as of December 31, 2004 and 2005 and our consolidated statement of operations data for the years ended December 31, 2003, 2004 and 2005 are derived from RAM Energy s consolidated financial statements audited by UHY Mann Frankfort Stein & Lipp CPAs, LLP, independent registered public accountants, and are included elsewhere in this prospectus. The consolidated balance sheet data as of December 31, 2003 and the consolidated statement of operations data for the year ended December 31, 2002 are derived from RAM Energy s consolidated financial statements audited by UHY Mann Frankfort Stein & Lipp CPAs, LLP, independent registered public accountants, which are not included in this prospectus. The consolidated balance sheet data of RAM Energy as of December 31, 2001 and 2002 and the consolidated statement of operations data for the year ended December 31, 2001 are derived from RAM Energy s unaudited consolidated financial statements, which are not included in this prospectus.

The selected consolidated financial information presented below should be read in conjunction with the historical consolidated financial statements of each of RAM Energy and Tremisis and the related notes, and *Management s Discussion and Analysis of Financial Condition and Results of Operations* contained elsewhere in this prospectus. The historical results included below and elsewhere in this prospectus may not be indicative of our future performance. RAM Energy s financial position and results of operations for 2003, 2004 and 2005 may not be comparative to other periods as a result of certain divestitures and acquisitions, as more fully described in RAM Energy s financial statements included elsewhere in this prospectus.

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Selected Consolidated Financial Data

(in thousands, except share data)

	Year Ended December 31,					Nine Months Ended September 30,	
	2001	2002	2003	2004	2005 (1)	2005 (1)	2006 (1)
						(unaudited)	
Revenues and Other Operating Income:							
Oil and natural gas sales	$ 25,404	$ 10,166	$ 20,053	$ 17,975	$ 66,243	$ 48,140	$ 53,050
Pipeline system	15,602						
Gain on sale of subsidiary				12,139			
Other	210	163	170	338	851	983	466
Realized and unrealized gains (losses) from derivatives		(146)	(203)	(793)	(11,695)	(16,613)	1,108
Total revenues and other operating income	41,216	10,183	20,020	29,659	55,399	32,510	54,624
Operating Expenses:							
Oil and natural gas production taxes	2,755	1,044	1,408	1,263	3,320	2,460	2,527
Oil and natural gas production expenses	5,975	3,023	3,527	3,600	16,099	11,453	13,222
Pipeline purchases	12,227						
Pipeline operations	489						
Depreciation and amortization	9,766	2,947	4,098	3,273	12,972	9,213	10,019
Accretion expense			48	78	510	217	398
Contract termination and severance payments	1,104						
Share-based compensation							2,218
General and administrative, net of operator s overhead fees	4,061	5,858	6,331	6,601	8,610	6,285	6,351
Total operating expenses	36,377	12,872	15,412	14,815	41,511	29,628	34,735
Operating income (loss)	4,839	(2,689)	4,608	14,844	13,888	2,882	19,889
Other Income (Expense):							
Gain on early extinguishment of debt		32,883					
Gain on sale of oil and natural gas properties	17,320						
Interest expense	(14,514)	(9,240)	(4,912)	(5,070)	(12,614)	(8,769)	(13,213)
Interest income	104	277	41	35	75	41	238
Income (Loss) from Continuing Operations Before Income Taxes and Extraordinary Item	7,749	21,231	(263)	9,809	1,349	(5,846)	6,914
Income Tax Provision (Benefit)	2,900	7,975	228	3,733	806	(2,222)	2,924
Income (Loss) from Continuing Operations Before Extraordinary Item	4,849	13,256	(491)	6,076	543	(3,624)	3,990
Extraordinary loss on acquisition of debt, net of income tax benefit of $674	(1,098)						
Income (Loss) from Continuing Operations	3,751	13,256	(491)	6,076	543	(3,624)	3,990

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Selected Consolidated Financial Data (continued)

(in thousands, except share data)

	Year Ended December 31,					Nine Months Ended September 30, (unaudited)	
	2001	**2002**	**2003**	**2004**	**2005 (1)**	**2005 (1)**	**2006 (1)**
Discontinued operations:							
Loss from discontinued operations		(18,016)	(1,723)				
Income tax benefit		(6,846)	(655)				
Loss from discontinued operations		(11,170)	(1,068)				
Income (loss) before cumulative effect of change in accounting principle	3,751	2,086	(1,559)	6,076	543	(3,624)	3,990
Cumulative effect of change in accounting principle (net of tax benefit of $275)			(448)				
Net income (loss)	$ 3,751	$ 2,086	$ (2,007)	$ 6,076	$ 543	$ (3,624)	$ 3,990
Net income (loss) per share attributable to common stockholders basic							
Income (loss) from continuing operations before extraordinary item	$ 1.78	$ 4,861.01	$ (180.05)	$ 2,383.67	$ 238.94	$ (0.47)	$ 0.19
Extraordinary loss	(0.40)						
Loss from discontinued operations		(4,096.08)	(391.64)				
Cumulative effect of change in accounting principle			(164.28)				
Net income (loss) per share	$ 1.38	$ 764.93	$ (735.97)	$ 2,383.67	$ 238.94	$ (0.47)	$ 0.19
Cash dividends per share	$	$	$ 294.83	$ 470.77	$ 615.93	$ 0.12	$ 0.02
Earnings (loss) per share:							
Basic	$ 1.38	$ 764.93	$ (735.97)	$ 2,383.67	$ 238.94	$ (0.47)	$ 0.19
Diluted	1.38	764.93	(735.97)	2,299.77	230.72	(0.47)	0.18
Weighted average shares outstanding:							
Basic	2,727,000	2,727	2,727	2,549	2,273	7,700,000	21,501,633
Diluted	2,727,000	2,727	2,727	2,642	2,354	7,700,000	21,105,987
Statement of Cash Flow Data							
Cash provided by (used in):							
Operating activities	$ 2,240	$ (14,842)	$ 5,774	$ 1,793	$ 18,359	$ 10,616	$ 25,294
Investing activities	44,520	(46)	7,422	(64,852)	(12,554)	(9,877)	(18,710)
Financing activities	(27,803)	(3,731)	(12,333)	62,116	(6,910)	(161)	938
Other Data							
Capital expenditures (2)	$ 11,349	$ 6,700	$ 5,258	$ 102,719	$ 13,526	$ 11,078	$ 21,529
EBITDA	14,709	473	8,670	18,153	33,747	27,208	26,888

	As of December 31,					As of September 30,
	2001	**2002**	**2003**	**2004**	**2005 (1)**	**2006 (1)**

						(unaudited)
Balance Sheet Data						
Total assets	$ 98,322	$ 62,192	$ 45,908	$ 140,324	$ 143,276	$ 158,157
Long-term debt, including current portion	91,400	56,267	46,057	117,344	112,846	131,696
Stockholders deficit	(20,347)	(16,842)	(19,653)	(19,912)	(20,769)	(29,043)

(1) We acquired WG Energy Holdings, Inc., in December 2004.

(2) Includes costs of acquisitions.

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Our EBITDA is determined by adding the following to net income (loss): interest expense, amortization, depreciation, accretion, income taxes, gain on early extinguishment of debt, gain on sale of oil and natural gas properties, share-based compensation, extraordinary gains (losses), the cumulative effect of changes in accounting principles and unrealized gains (losses) on derivatives. The table below reconciles EBITDA to net income (loss).

We present EBITDA because we believe that it provides useful information regarding our continuing operating results. We rely on EBITDA as a primary measure to review and assess our operating performance with corresponding periods, and as an assessment of our overall liquidity and our ability to meet our debt service obligations.

We believe that EBITDA is useful to investors to provide disclosure of our operating results on the same basis as that used by our management. We also believe that this measure can assist investors in comparing our performance to that of other companies on a consistent basis without regard to certain items that do not directly affect our ongoing operating performance or cash flows. EBITDA, which is not a financial measure under generally accepted accounting principles, or GAAP, has limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for net income, cash flows from operating activities and other consolidated income or cash flows statement data prepared in accordance with GAAP. Because of these limitations, EBITDA should neither be considered as a measure of discretionary cash available to us to invest in the growth of our business, nor as a replacement for net income. We compensate for these limitations by relying primarily on our GAAP results and using EBITDA as supplemental information.

	Year ended December 31,					Nine Months Ended September 30, (unaudited)	
	2001	2002	2003	2004	2005	2005	2006
	(in thousands)						
Reconciliation of EBITDA to net income (loss):							
Net income (loss)	$ 3,751	$ 2,086	$ (2,007)	$ 6,076	$ 543	$ (3,624)	$ 3,990
Plus: Interest expense	14,514	9,240	4,912	5,070	12,614	8,769	13,213
Plus: Amortization and depreciation expense	9,766	2,947	4,098	3,273	12,972	9,213	10,019
Plus: Accretion expense			48	78	510	217	398
Plus: Income tax expense (benefit)	2,900	7,975	228	3,733	806	(2,222)	2,924
Less: Gain on early extinguishment of debt		(32,883)					
Less: Gain on sale of oil and natural gas properties	(17,320)						
Plus: Share-based compensation							2,218
Plus: Extraordinary (gain) loss	1,098						
Plus: Loss from discontinued operations, net of tax		11,170	1,068				
Less: Cumulative effect of change in accounting principle			448				
Plus: Unrealized (gain) loss on derivatives		(62)	(125)	(77)	6,302	14,855	(5,874)
EBITDA	$ 14,709	$ 473	$ 8,670	$ 18,153	$ 33,747	$ 27,208	$ 26,888

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MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

General

We are an independent oil and natural gas company engaged in the acquisition, development, exploitation, exploration and production of oil and natural gas properties, primarily in Texas, Louisiana and Oklahoma. Through our RAM Energy subsidiary, we have been active in these core areas since 1987. Our management team has extensive technical and operating expertise in all areas of our geographic focus.

Prior to May 8, 2006, our corporate name was Tremisis Energy Acquisition Corporation. On May 8, 2006, we acquired RAM Energy through the merger of our recently formed, wholly owned subsidiary into RAM Energy. The merger was accomplished pursuant to the terms of an Agreement and Plan of Merger dated October 20, 2005, as amended, which we refer to as the merger agreement, among us, our acquisition subsidiary, RAM Energy and the stockholders of RAM Energy. Upon completion of the merger, RAM Energy became our wholly owned subsidiary and we changed our name from Tremisis Energy Acquisition Corporation to RAM Energy Resources, Inc.

Upon consummation of the merger, the stockholders of RAM Energy received an aggregate of 25,600,000 shares of our common stock and $30.0 million of cash. Prior to consummation of the merger, and as permitted by the merger agreement, on April 6, 2006, RAM Energy redeemed a portion of its outstanding stock for an aggregate consideration of $10.0 million.

The merger is accounted for as a reverse acquisition. RAM Energy has been treated as the acquiring company and the continuing reporting entity for accounting purposes. Upon completion of the merger, the assets and liabilities of Tremisis were recorded at their fair value, which is considered to approximate historical cost, and added to those of RAM Energy. Because Tremisis had no active business operations prior to consummation of the merger, the merger was accounted for as a recapitalization of RAM Energy.

In December 2004, RAM Energy acquired WG Energy Holdings, Inc. for $82.6 million, which we refer to as the WG Energy Acquisition. Upon consummation of the WG Energy Acquisition, we changed WG Energy Holdings, Inc. s name to RWG Energy, Inc.

Critical Accounting Policies

The preparation of our financial statements in conformity with generally accepted accounting principles requires our management to make estimates and assumptions that affect our reported assets, liabilities and contingencies as of the date of the financial statements and our reported revenues and expenses during the related reporting period. Our actual results could differ from those estimates.

We use the full cost method of accounting for our investment in oil and natural gas properties. Under the full cost method of accounting, all costs of acquisition, exploration and development of oil and natural gas reserves are capitalized into a full cost pool as incurred, and costs included in the pool are amortized and charged to operations using the future recoverable units of production method based on the ratio of current production to total proved reserves, computed based on current prices and costs. Significant downward revisions of quantity estimates or declines in oil and natural gas prices that are not offset by other factors could result in a write-down for impairment of the carrying value of our oil and natural gas properties. Once incurred, a write-down of the value of oil and gas properties is not reversible at a later date, even if quantity estimates or oil or natural gas prices subsequently increase.

Under Statement of Financial Accounting Standards No. 109 (SFAS No. 109), Accounting for Income Taxes, deferred income taxes are recognized at each year end for the future tax consequences of differences between the tax bases of assets and liabilities and their financial reporting amounts based on tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable

income. We routinely assess the realizability of our deferred tax assets. We consider future taxable income in making such assessments. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, it is reduced by a valuation allowance. However, despite our attempt to make an accurate estimate, the ultimate utilization of our deferred tax assets is highly dependent upon our actual production and the realization of taxable income in future periods.

Results of Operations

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

Revenues and Other Operating Income. Our revenues and other operating income increased by $22.1 million, or 68%, for the nine months ended September 30, 2006, compared to the nine months ended September 30, 2005. The following table summarizes our oil and natural gas sales, production volumes, average sales prices and period-to-period comparisons for the periods indicated (dollars in thousands, except average sales prices):

	Nine months ended September 30,		Increase
	2005	**2006**	**(Decrease)**
Oil and natural gas sales:			
RAM Energy	$ 11,393	$ 10,916	(4.2)%
RWG (WG Energy Acquisition)	36,747	42,134	14.7%
Total	$ 48,140	$ 53,050	10.2%
Production volumes:			
Oil (MBbls):			
RAM Energy	69	64	(7.3)%
RWG (WG Energy Acquisition)	525	528	0.6%
Total	594	592	(0.3)%
NGL (MBbls):			
RAM Energy	4	3	(25.1)%
RWG (WG Energy Acquisition)	126	100	(21.0)%
Total	130	103	(21.1)%
Natural gas (MMcf):			
RAM Energy	1,163	993	(14.6)%
RWG (WG Energy Acquisition)	666	769	15.4%
Total	1,828	1,761	(3.6)%
Average sale prices:			
Oil (per Bbl)	$ 53.22	$ 63.80	19.9%
NGL (per Bbl)	35.28	41.89	18.7%
Natural gas (per Mcf)	6.52	6.22	(4.5)%
Per Boe	46.77	53.66	14.7%

Oil and Natural Gas Sales. Our oil and natural gas revenues increased by $4.9 million, or 10.2%, for the nine months ended September 30, 2006, as compared to the nine months ended September 30, 2005, due primarily to a 15% increase in average product prices.

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Before giving effect to an outstanding reversionary interest in our Boonsville shallow gas area, our daily average production in the first nine months of 2006 would have been 3,803 Boe per day versus 3,770 Boe per day for the nine months ended September 30, 2005, an increase of 1%. The outstanding reversionary interest, which vested in September 2005, impacted daily production for the first three quarters of 2006 production by 5%, resulting in actual average daily production being 3,621 Boe per day versus 3,770 Boe per day for the nine months ended September 30, 2005.

For the nine months ended September 30, 2006, our oil production decreased less than 1%, NGL production decreased 21%, and natural gas production decreased 4%, compared to the first nine months of the previous year. Our average realized sales price for oil was $63.80 per Bbl for the nine months ended September 30, 2006, an increase of 20% compared to $53.22 per Bbl for the nine months ended September 30, 2005. Our average realized NGL price for the nine months ended September 30, 2006 was $41.89 per Bbl, a 19% increase compared to $35.28 per Bbl for the nine months ended September 30, 2005. Our average realized natural gas price was $6.22 per Mcf for the nine months ended September 30, 2006, a decrease of 5% compared to $6.52 per Mcf for the comparable nine months of 2005.

Other Revenues. Other revenues for the nine months ended September 30, 2006 decreased by 53% to $466,000, compared to the nine months ended September 30, 2005 other revenues and operating income of $983,000.

Realized and Unrealized Gain (Loss) from Derivatives. For the nine months ended September 30, 2006, our gain from derivatives was $1.1 million, compared to a loss of $16.6 million for the first nine months of 2005. Our gains and losses during these periods were the net result of recording actual contract settlements, the premium costs paid for various derivative contracts, and unrealized mark-to-market values of our derivative contracts as shown in the following table (in thousands):

	Nine months ended September 30,	
	2005	**2006**
Contract settlements and premium costs:		
Oil	$ (1,820)	$ (4,328)
Natural gas	(280)	(438)
Realized (losses)	(2,100)	(4,766)
Mark-to-market gains (losses):		
Oil	(4,957)	1,676
Natural gas	(9,556)	4,198
Unrealized gains (losses)	(14,513)	5,874
Realized and unrealized gains (losses)	$ (16,613)	$ 1,108

For a further discussion of our realized and unrealized loss from derivatives, please see *Quantitative and Qualitative Disclosures About Market Risks Commodity Price Risk*.

Oil and Natural Gas Production Taxes. Our oil and natural gas production taxes for the nine months ended September 30, 2006, were $2.5 million, an increase of $67,000, or 3%, from the first three quarters of the previous year. Production taxes are based on realized prices at the wellhead. As revenues from oil and natural gas sales increase or decrease, production taxes on these sales increase or decrease also. As a percentage of oil and natural gas sales, oil and natural gas production taxes were 4.8% for the nine months ended September 30, 2006, compared to 5.1% for the nine months ended September 30, 2005.

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Oil and Natural Gas Production Expense. Our oil and natural gas production expense was $13.2 million for the nine months ended September 30, 2006, an increase of $1.8 million, or 15%, from the $11.4 million for the nine months ended September 30, 2005. The increase was primarily due to increased utility

costs and higher maintenance costs due to additional producing wells. For the nine months ended September 30, 2006, our oil and natural gas production expense was $13.38 per Boe compared to $11.13 per Boe for the nine months ended September 30, 2005, an increase of 20%. As a percentage of oil and natural gas sales, oil and natural gas production expense increased to 25% for the nine months ended September 30, 2006 compared to 24% for the first nine months in 2005.

Amortization and Depreciation Expense. Our amortization and depreciation expense increased $806,000, or 9%, for the nine months ended September 30, 2006, compared to the nine months ended September 30, 2005. The increase was a result of higher capitalized costs due to increased drilling. On an equivalent basis, our amortization of the full cost pool of $9.5 million was $9.63 per Boe for the nine months ended September 30, 2006, an increase per Boe of 14% compared to $8.7 million, or $8.43 per Boe, for the nine months ended September 30, 2005.

Accretion Expense. SFAS No. 143, Accounting for Asset Retirement Obligations, includes, among other things, the reporting of the fair value of asset retirement obligations. Accretion expense is a function of changes in fair value from period-to-period. We recorded $398,000 for the nine months ended September 30, 2006, compared to $217,000 for the nine months ended September 30, 2005.

Share-Based Compensation. Concurrent with our acquisition of RAM Energy, Inc. on May 8, 2006, our Board of Directors awarded grants of an aggregate 330,000 shares of our common stock to certain of our senior officers and directors under our 2006 Long-Term Incentive Plan. For the nine months ended September 30, 2006, our share-based compensation was $2.2 million, calculated at a closing price on May 8, 2006, the day the shares were granted, of $6.72 per share.

General and Administrative Expense. For the nine months ended September 30, 2006, our general and administrative expense was $6.4 million, compared to $6.3 million for the nine months ended September 30, 2005, an increase of $66,000, or 1%.

Interest Expense. Our interest expense increased by $4.4 million to $13.2 million for the nine months ended September 30, 2006, compared to the $8.8 million incurred for the nine months ended September 30, 2005. During the second quarter we charged off $1.1 million of unamortized costs associated with our previous credit facility and we paid $1.0 million in prepayment premiums. The remaining interest expense of $11.1 million represents an increase of $2.3 million, or 26%, over the $8.8 million reported for the nine months ended September 30, 2005. This increase was due to higher interest rates and higher outstanding indebtedness during the 2006 period.

Income Taxes. For the nine months ended September 30, 2006, we recorded an income tax expense of $2.9 million on pre-tax income of $6.9 million. For the nine months ended September 30, 2005, the income tax effect was a $2.2 million benefit, on a pre-tax loss of $5.8 million. The effective tax rate for the nine month period was 42% and 38% in 2006 and 2005, respectively.

Net Income. Our net income was $4.0 million for the nine months ended September 30, 2006, compared to a net loss of $3.6 million for the nine months ended September 30, 2005. The income for the first three quarters of 2006 results from increased prices and gains on derivatives, partially offset by non-cash charges to share-based compensation and the remaining unamortized costs associated with our previous credit facility.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Revenues and Other Operating Income. Our revenues and other operating income increased by $26.0 million, or 87%, for the year ended December 31, 2005, compared to the year ended December 31, 2004.

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The following table summarizes our oil and natural gas sales, production volumes, average sales prices and period-to-period comparisons for the periods indicated (dollars in thousands except average sales prices):

	Year Ended December 31, 2004	Year Ended December 31, 2005	Increase (Decrease)
Oil and natural gas sales:			
RAM Energy	$ 16,540	$ 16,486	(0.3)%
RWG (WG Energy Acquisition)	1,435	49,757	3,367.4%
Total	$ 17,975	$ 66,243	268.5%
Production volumes:			
Oil (Mbls):			
RAM Energy	151	95	(36.9)%
RWG (WG Energy Acquisition)	27	692	2,463.0%
Total Oil (Mbls)	178	787	342.0%
NGL (Mbls):			
RAM Energy	7	7	0%
RWG (WG Energy Acquisition)	5	163	3,160.0%
Total NGL (Mbls)	12	170	1,316.7%
Natural gas (MMcf):			
RAM Energy	1,901	1,666	(12.4)%
RWG (WG Energy Acquisition)	27	1,015	3,659.3%
Total natural gas (MMcf)	1,928	2,681	39.0%
Average sale prices:			
Oil (per Bbl)	$ 37.63	$ 53.75	43.0%
NGL (per Bbl)	26.41	36.33	37.6%
Natural gas (per Mcf)	5.69	6.61	16.3%

Oil and Natural Gas Sales. Our oil and natural gas revenues were higher for the year ended December 31, 2005, as compared to the year ended December 31, 2004, with a 175% increase in production due, primarily, to the properties included in the WG Energy Acquisition and a 34% increase in realized prices, both on a Boe basis.

Our average daily production was 3.8 MBoe in the year ended December 31, 2005, compared to 1.4 MBoe for the year ended December 31, 2004, an increase of 175%. For the year ended December 31, 2005, our oil production increased 342%, our NGL production increased 1,317% and our natural gas production increased 39% compared to the year ended December 31, 2004. Our average realized sales price for oil was $53.75 per Bbl for the year ended December 31, 2005, an increase of 43% compared to $37.63 per Bbl for the year ended December 31, 2004. Our average realized NGL price for the year ended December 31, 2005, was $36.33 per Bbl, a 38% increase compared to $26.41 per Bbl for the year ended December 31, 2004. Our average realized natural gas price was $6.61 per Mcf for the year ended December 31, 2005, an increase of 16% compared to $5.69 per Mcf for the year ended December 31, 2004.

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Decreases in production shown above, excluding effects of our WG Energy Acquisition, are due primarily to the following volumes and values of our former wholly owned subsidiary, RB Operating Company, or RBOC, included through the end of April 2004:

	Year Ended December 31, 2004
Oil and natural gas sales (in thousands)	$ 2,302
Production volumes:	
Oil (Mbls)	47
Natural gas (MMcf)	410
Average sale prices:	
Oil (per Bbl)	$ 33.49
Natural gas (per Mcf)	$ 5.68

Gain On Sale of Subsidiary. On April 29, 2004, we completed the sale of all of the outstanding capital stock of our subsidiary, RBOC, for gross proceeds of $22.5 million. After adjustments for closing costs, we reported a gain of $12.1 million. The assets of RBOC at the time of the sale consisted entirely of oil and natural gas properties located in New Mexico, together with cash, accounts receivable and certain liabilities.

Other Revenues and Operating Income. Our other revenues and operating income for the year ended December 31, 2005 increased $513,000, or 152%, over the year ended December 31, 2004 due, primarily, to an increase in consulting service fees of approximately $200,000, sales of oilfield supplies of approximately $100,000, and numerous other non-material items.

Realized and Unrealized Loss from Derivatives. For the year ended December 31, 2005, our loss from derivatives was $11.7 million, compared to a loss of $793,000 for the year ended December 31, 2004. Our losses during these periods were the net result of recording unrealized mark-to-market values of our contracts, the premium costs paid for various derivative contracts, and actual contract settlements.

	Year Ended December 31, 2004	Year Ended December 31, 2005
Contract settlements	$ (690)	$ (3,902)
Premium costs	(180)	(1,491)
Realized losses	(870)	(5,393)
Mark-to-market gains (losses)	77	(6,302)
Realized and unrealized losses	$ (793)	$ (11,695)

Oil and Natural Gas Production Taxes. Our oil and natural gas production taxes for the year ended December 31, 2005, were $3.3 million, an increase of $2.0 million, or 163%, from the $1.3 million incurred for the year ended December 31, 2004. Of the increase in production taxes for the year ended December 31, 2005, $2.3 million was attributable to our WG Energy Acquisition, while our production taxes decreased $300,000. Production taxes are based on realized prices at the wellhead. As revenues from oil and natural gas sales increase or decrease, production taxes on these sales increase or decrease also. As a percentage of oil and natural gas sales, oil and natural gas production taxes were 5.0% for the year ended December 31, 2005, compared to 7.0% for the year ended December 31, 2004. The reason for this decrease in percentage is because, after our WG Energy Acquisition, our greatest revenue source is oil sales in Texas, which are taxed at a 4.6% rate.

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Oil and Natural Gas Production Expense. Our oil and natural gas production expense was $16.1 million for the year ended December 31, 2005, an increase of $12.5 million, or 347%, from $3.6 million for the year ended December 31, 2004. The increase of $12.8 million for the year ended December 31, 2005 was due to our WG Energy Acquisition, while our oil and natural gas production expense decreased $300,000. For the year ended December 31, 2005, our oil and natural gas production expense was $11.46 per Boe compared to $7.04 per Boe for the year ended December 31, 2004, an increase of 63%. As a percentage of oil and natural gas sales, oil and natural gas production expense increased from 20% for the year ended December 31, 2004, to 24% for the year ended December 31, 2005. The reason for the increase in costs, both in absolute amount and on a per Bbl basis is that one of the major fields included in our WG Energy Acquisition is a cost intensive, shallow water-flood unit. Fixed costs of the shallow water-flood unit, such as payroll, utilities, insurance, property and ad valorem taxes, regulatory compliance, and maintenance account for approximately 85% of the total operating costs. Repairs account for the balance. Our management expects that operating costs will remain at this level for the foreseeable future.

Amortization and Depreciation Expense. Our amortization and depreciation expense increased $9.7 million, or 298%, for the year ended December 31, 2005, compared to the year ended December 31, 2004. Our WG Energy Acquisition accounted for $9.7 million of the increase, offset by a $200,000 decrease for RAM. On an equivalent basis, our amortization of the full cost pool of $12.5 million was $8.93 per Boe for the year ended December 31, 2005, an increase per Boe of 52% compared to $3.0 million, or $5.89 per Boe for the year ended December 31, 2004.

Accretion Expense. SFAS No. 143, *Accounting for Asset Retirement Obligations,* includes, among other things, the reporting of the fair value of asset retirement obligations. Accretion expense is a function of changes in fair value from period-to-period, and we recorded $510,000 for the year ended December 31, 2005, compared to $78,000 for the year ended December 31, 2004. The increase of $432,000 for the year ended December 31, 2005 was due to the higher amount of the asset retirement obligation attributable to our WG Energy Acquisition.

General & Administrative Expense. For the year ended December 31, 2005, our general and administrative expense was $8.6 million and increased $2.0 million, or 30%, as compared with the $6.6 million reported for the year ended December 31, 2004. This increase was due primarily to the increased costs of accounting services, higher benefits, salaries, travel and legal fees during the 2005 period.

Interest Expense. Our interest expense increased by $7.5 million to $12.6 million for the year ended December 31, 2005, compared to $5.1 million for the year ended December 31, 2004. This increase was attributable to higher outstanding balances, primarily to fund the WG Energy Acquisition, and higher interest rates during the 2005 period.

Income Taxes. For the year ended December 31, 2005, we recorded income tax expense of $806,000 an effective tax rate of 60%, on pre-tax income of $1.3 million. The provision for income taxes differs from the amount computed by applying the statutory federal income tax rate to income before provision for income taxes. The significant differences between pre-tax book income and taxable book income relate to non-deductible expenses, such as unrealized losses from derivatives.

For the year ended December 31, 2004, we recorded an income tax provision of $3.7 million, based on an effective tax rate of 38%, on pre-tax income of $9.8 million.

Net Income (Loss). Our net income was $543,000 for the year ended December 31, 2005, compared to net income of $6.0 million for the year ended December 31, 2004. The decrease in our net income for 2005 compared to 2004 was primarily attributable to realized losses from derivatives, increases in oil and natural gas production expenses and taxes, amortization and depreciation expenses, interest expense and general and administrative expenses.

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

Revenue and Other Operating Income. Our operating revenues increased by $9.6 million, or 48%, for the year ended December 31, 2004, compared to the year ended December 31, 2003.

The following table summarizes our oil and natural gas sales, production, average sales prices and period-to-period comparisons for the periods indicated:

	Year Ended December 31,		% Increase
	2003	2004	(Decrease)
Oil and natural gas sales (in thousands).	$ 20,053	$ 17,975	(10.4)%
Production volumes:			
Oil (MBbls)	277	178	(35.8)%
Natural gas liquids (MBbls)	5	12	140.0 %
Natural gas (MMcf)	2,334	1,928	(17.4)%
Average net sales prices:			
Oil (per Bbl)	$ 29.47	$ 37.63	27.7 %
Natural gas liquids (per Bbl)	16.94	$ 26.41	55.9 %
Natural gas (per Mcf)	5.06	5.69	12.4 %

Oil and Natural Gas Sales. Our oil and natural gas sales revenues were lower in 2004 compared to 2003 with a 24% decrease in production due, primarily, to the sale of our subsidiary, RBOC, on April 29, 2004, partially offset by an 18% increase in realized prices, on a Boe basis. Our average daily production was 1,400 Boe in 2004 compared to 1,838 Boe during 2003, a decrease of 24%. For 2004, our natural gas production decreased by 17% and oil production decreased 36% compared to 2003. The average sale price realized by us for oil for 2004 was $37.63 per Bbl, a 28% increase from the $29.47 received for 2003, and for natural gas was $5.69 per Mcf for 2004, compared to $5.06 per Mcf for 2003, an increase of 12%.

Gain On Sale of Subsidiary. On April 29, 2004, we completed the sale of all of the outstanding capital stock of our wholly owned subsidiary, RBOC, for gross proceeds of $22.5 million. After adjustments for closing costs, we reported a gain of $12.1 million. The assets of RBOC at the time of the sale consisted of oil and natural gas properties located in New Mexico, cash, accounts receivable and certain liabilities.

Realized and Unrealized Loss from Derivatives. For 2004, our loss from derivatives was $793,000. For 2003, we recorded a loss from derivatives of $203,000. These losses were the net result of contract settlements, premium costs of various derivative contracts, and mark-to-market values of those contracts at year-end (in thousands).

	2003	2004
Contract settlements	$	$ (690)
Premium costs	(328)	(180)
Realized losses	(328)	(870)
Mark-to-market gains	125	77
Realized and unrealized losses	$ (203)	$ (793)

Oil and Natural Gas Production Taxes. Our oil and natural gas production taxes for 2004 were $1.3 million, a decrease of $145,000, or 10%, from $1.4 million for 2003. As a percentage of wellhead prices received, these production taxes were 7% for both 2004 and 2003.

Oil and Natural Gas Production Expense. Our oil and natural gas production expense for 2004 was $3.6 million, an increase of $73,000, or 2%, from $3.5 million for 2003. Our oil and natural gas production

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expense was 20% of sales of oil and natural gas, or $7.04 per Boe for 2004, compared to 18%, or $5.26 per Boe for 2003. This increase was due primarily to $568,000 attributable to RWG production expense in the 2004 period, offset by a decrease caused by the sale of RBOC.

Accretion Expense. We adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, during the first quarter of 2003. One aspect of SFAS No. 143 is the reporting of the fair value of asset retirement obligations. Accretion expense is a function of changes in fair value from period-to-period. We recorded $78,000 of accretion expense for 2004, compared to $48,000 for 2003.

Amortization and Depreciation Expense. Our amortization and depreciation expense for 2004 was $3.3 million, a decrease of $825,000, or 20%, compared to $4.1 million for 2003. This decrease was due primarily to lower production during 2004. On a Boe basis, the amortization of our full cost pool was $5.89 per Boe for 2004, an increase of 4% compared to $5.64 per Boe for 2003.

General & Administrative Expense. Our general and administrative expense for 2004 was $6.6 million, an increase of $270,000, or 4% over our general and administrative expense of $6.3 million recorded for 2003. The increase was due primarily to increased salaries and benefits to employees, excluding officers, during 2004.

Interest Expense. Our interest expense increased by $158,000 to $5.1 million for 2004 compared to $4.9 million for 2003. This increase for 2004 was attributable to higher average interest rates during 2004, the write-off of deferred loan costs of $309,000, and the allocation in 2003 of $609,000 to discontinued operations.

Income Taxes. Our overall effective tax rate for 2004 and 2003 was 38% and (87%), respectively.

Loss from Discontinued Operations. On July 31, 2003, we sold our 145-mile oil and natural gas pipeline system located in the Anadarko Shelf area in Oklahoma to Continental Gas, Inc., or CGI, for $15.0 million, effective August 1, 2003, subject to certain adjustments. The sale price was reduced by $3.0 million in consideration of the settlement and mutual release by our subsidiary, Great Plains Pipeline Company, or GPPC, and by CGI of all claims that were or could have been asserted by CGI and GPPC in a lawsuit filed by CGI in September 2003, relating to disputes arising under a gas service contract between the parties. We received net sale proceeds of $11.8 million after all adjustments and less expenses relating to the sale.

The results of our discontinued operations for the year ended December 31, 2003 are as follows (in thousands):

Pipeline system revenue	$ 14,500
Pipeline system costs and expenses:	
Purchases	12,066
Operating costs	598
Depreciation	388
Impairment	2,562
Interest	609
Total system costs and expenses	16,223
Loss from discontinued operations	(1,723)
Income tax benefit	(655)
Loss from discontinued operations	$ (1,068)

Net Income. We recorded net income of $6.1 million for 2004 compared to a net loss of $2.0 million for 2003, due primarily to the sale of RBOC.

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Liquidity and Capital Resources

As of September 30, 2006, we had net working capital of $670,000, a ratio of current assets to current liabilities of 1.1 to 1, cash and cash equivalents of $7.6 million, and $37.0 million was available under our revolving credit facility. At that date, we had $131.7 million of indebtedness outstanding, including $103.0 million under our credit facility, $28.4 million principal amount ($28.3 million net of the original issue discount) of indebtedness evidenced by RAM Energy, Inc. s 11 1/2% senior notes due 2008, and $356,000 in other indebtedness. On September 22, 2006, we repurchased 739,175 shares of our common stock from an unaffiliated party in a negotiated transaction, at a purchase price of $4.295 per share.

Credit Facility. On April 5, 2006, RAM Energy, Inc. entered into a Third Amended and Restated Loan Agreement with Guggenheim Corporate Funding, LLC, for itself and as Agent for a group of lenders. This facility, which we refer to as the Guggenheim facility, amended, restated and replaced a prior credit facility known as the Foothill facility. Currently, we are not a party to, or a guarantor of obligations under, the Guggenheim facility. As part of the transaction creating the Guggenheim facility, Foothill assigned the notes and liens under the Foothill facility to the Agent for the lenders under the Guggenheim facility. The Guggenheim facility includes a $150.0 million revolving credit facility of which $50.0 million was immediately available, and a $150.0 million term loan facility of which $90.0 million was advanced at closing. The remainder of the term loan facility may become available, subject to approval of each lender desiring to fund its proportionate share of the additional term loan advance, for certain of the future needs of RAM Energy, Inc., including acquisitions. The Guggenheim revolving credit facility is scheduled to mature in four years, during which time amounts may be borrowed, repaid and re-borrowed, subject to a borrowing base limitation to be determined by the lenders. The term loan facility is scheduled to mature in five years, with permitted prepayments after the first year, subject to a prepayment premium in the second and third years of the term. Advances under the revolving credit facility bear interest at LIBOR plus 2% per annum, while amounts outstanding under the term loan bear interest at LIBOR plus 5 1/2% to 6% per annum. Obligations under the Guggenheim facility are secured by liens on substantially all of the assets of RAM Energy, Inc. and its subsidiaries. The initial advance under the Guggenheim facility was used to refinance the Foothill facility, to pay expenses associated with establishing the Guggenheim facility, and to fund a $10.0 million redemption payment. Subsequent advances may be used to:

- repurchase all of RAM Energy, Inc. s outstanding 11 1/2% senior notes due 2008 ($28.4 million principal amount); and

- fund general working capital purposes.

The Guggenheim facility contains financial covenants requiring RAM Energy, Inc. to maintain certain ratios, including a current ratio, a ratio of EBITDA to interest expense, a ratio of total indebtedness to EBITDA, and a ratio of asset value to total indebtedness. In addition, the Guggenheim facility contains other affirmative and negative covenants customary in lending transactions of this nature, including restrictions on the payment of dividends and the maintenance by RAM Energy, Inc. of derivative contracts on not less than 50% nor more than 85% of RAM Energy, Inc. s projected oil and natural gas production from its properties on a rolling 24-month period; provided that the derivative requirements will be waived for any quarter in which RAM Energy Inc. s leverage ratio is less than 2.0 to 1.0.

Senior Notes. On February 24, 1998, RAM Energy, Inc. issued $115.0 million principal amount of its 11 1/2% senior notes which mature February 15, 2008. Currently, we are not a party to, or a guarantor of, the senior notes or of any obligations under the indenture covering the senior notes. At September 30, 2006, RAM Energy, Inc. had outstanding $28.4 million aggregate principal amount of its senior notes. The notes bear interest at an annual rate of 11 1/2%, payable semi-annually on each February 15 and August 15. Pursuant to a Second Supplemental Indenture executed in November 2002, substantially all of the restrictive covenants and certain events of default contained in the original indenture were eliminated. We may redeem our outstanding senior notes prior to February 15, 2007 at 107.67% of the stated principal amount and thereafter at 103.84% until their maturity on February 15, 2008.

Cash Flow From Operating Activities. Our cash flow from operating activities is comprised of three main items: net income (loss), adjustments to reconcile net income to cash provided (used) before changes in working capital, and changes in working capital. For the nine months ended September 30, 2006, our net income was $4.0 million, as compared with net loss of $3.6 million for the nine months ended September 30, 2005. Adjustments (primarily non-cash items such as depreciation and amortization, unrealized (gain) loss on derivatives, share-based compensation and deferred income taxes) were $11.8 million for the nine months ended September 30, 2006 compared to $21.3 million for the first nine months of 2005, a decrease of $9.4 million. Unrealized gain on derivatives, partially offset by changes in deferred income taxes, was the primary reason for the decrease. Working capital changes for the nine months ended September 30, 2006 were a positive $9.5 million compared with negative changes of $7.0 million for the nine months ended September 30, 2005. For the nine months ended September 30, 2006, in total, net cash provided by operating activities was $25.3 million compared to $10.6 million of net cash provided by operations for the first three quarters of the previous year.

For the year ended December 31, 2005, our net income was $543,000, as compared with net income of $6.1 million for the year ended December 31, 2004. Net income for the 2004 period resulted primarily from gain recognized on the sale of RBOC. Adjustments (primarily non-cash items such as depreciation and amortization, unrealized loss on derivatives, gain on the sale of RBOC and deferred income taxes) were $21.8 million for the year ended December 31, 2005 compared to a negative adjustment of $11.1 million for the year ended December 31, 2004, an increase of $32.9 million. Working capital changes for the year ended December 31, 2005 were a negative $4.0 million compared with a positive $6.9 million for the year ended December 31, 2004. For the year ended December 31, 2005, in total, net cash provided by operating activities was $18.4 million compared to $1.8 million of net cash provided by operations for the year ended December 31, 2004.

For the year ended December 31, 2004, our net income was $6.1 million, compared with net loss of $2.0 million for the year ended December 31, 2003. Adjustments (primarily non-cash items such as depreciation and amortization, loss from discontinued operations, gain on early extinguishment of debt and deferred income taxes) were negative $11.1 million for the year ended December 31, 2004 compared to $2.1 million for the prior year, a decrease of $13.2 million. The $12.1 million gain on sale of subsidiary in 2004, $1.1 million loss from discontinued operations in 2003, and unrealized gain on derivatives, partially offset by changes in deferred income taxes, caused most of this decrease. Working capital changes for the year ended December 31, 2004 were a positive $6.9 million compared with changes of $5.7 million for the year ended December 31, 2003. Cash provided by discontinued operations was $898,000 in 2003. For the year ended December 31, 2004, net cash provided by operating activities was $1.8 million compared to $5.8 million of net cash provided by operations for the previous year.

Cash Flow From Investing Activities. For the nine months ended September 30, 2006, net cash used in our investing activities was $18.7 million, consisting of $21.5 million in payments for oil and natural gas properties and equipment and $726,000 in payments for other property and equipment, offset by $3.5 million of proceeds from the sale of undeveloped acreage, $366,000 in proceeds from the sale of other property and equipment, and $386,000 of net merger costs. The first nine months of 2006 reflected an 89% increase in cash used in investing activities compared to the first nine months of the previous year. For the nine months ended September 30, 2005, net cash used in our investing activities was $9.9 million, consisting of $11.1 million in payments for oil and natural gas properties and $1.1 million for other property and equipment additions, offset by $2.3 million in proceeds from the sale of oil and natural gas properties.

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For the year ended December 31, 2005, net cash used by our investing activities was $12.6 million, consisting of $13.5 million in payments for oil and natural gas properties and other property and equipment additions, offset partially by $2.5 million in proceeds from the sale of oil and natural gas properties. This compares with net cash used in our investing activities for the year ended December 31, 2004, of $64.9 million, consisting of $21.8 million in proceeds from the sale of RBOC, and $1.7 million in proceeds from short-term investments, offset by $88.7 million in net payment for property additions and the WG Energy Acquisition.

For the year ended December 31, 2004, net cash used by our investing activities was $64.9 million, which included $82.6 million net cash used for the WG Energy Acquisition, $5.9 million in payments for oil and natural gas properties and equipment, and $205,000 in payments for other property and equipment. Offsets to cash used in investing activities for 2004 included $21.8 million in proceeds from the sale of a subsidiary, $1.7 million in proceeds from short-term investments, and $358,000 in proceeds from sales of oil and natural gas properties and other equipment. For the year ended December 31, 2003, net cash provided by our investing activities was $7.4 million, consisting of $12.0 million of proceeds from the sale of pipeline system, and $202,000 of proceeds from the sale of oil, natural gas and other property, offset by $4.3 million in payments for oil and natural gas properties, $343,000 in payments for other property and equipment, and $181,000 in payments for short-term investments.

Cash Flow From Financing Activities. For the nine months ended September 30, 2006, net cash provided by our financing activities was $938,000, compared to net cash used of $161,000 for the nine months ended September 30, 2005. The cash provided in the first nine months of 2006 included an approximate $15.8 million net debt increase, partially offset by a stock redemption of $9.8 million, a stock repurchase of $3.8 million and $500,000 in dividends.

For the year ended December 31, 2005, net cash used by our financing activities was $6.9 million, compared to $62.1 million provided during the year ended December 31, 2004. The cash used in 2005 included $5.5 million in net debt reduction and $1.4 million in dividends. Cash provided in 2004 was primarily debt incurred for the WG Energy Acquisition.

For the year ended December 31, 2004, net cash provided by our financing activities was $62.1 million, compared to net cash used $12.3 million for the year ended December 31, 2003. The net cash provided in 2004 consisted of $70.4 million net borrowings on long-term debt, offset by $5.1 million used for stock repurchased and returned, $1.5 million in payments for deferred loan costs, and $1.6 million in dividends. The net cash used in 2003 included $11.9 million in payments on long-term debt and $404,000 in dividends.

Capital Commitments

We have budgeted $30.3 million for capital expenditures in 2007 related to:

- geological, geophysical and seismic costs ($2.9 million);
- developmental drilling and re-completions ($17.7 million); and
- exploratory drilling, including leasehold acquisitions ($9.7 million).

In our 2007 drilling and development budget, we have allocated $4.0 million to our north Texas Barnett Shale properties, $7.4 million to our Wolfcamp properties, $500,000 to our Woodford properties, $9.7 million to our Electra/Burkburnett properties, $1.6 million to our Boonsville properties, and $4.2 million to our other properties. Our budgeted allocations may change, depending on our drilling success, prices for oil and natural gas, general economic conditions and other factors beyond our control.

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During the nine months ended September 30, 2006, we had capital expenditures of $21.5 million relating to our oil and natural gas operations, of which $14.4 million was allocated to drilling new development wells, $1.9 million was for exploration costs, and $5.2 million was for acquisition costs. Our non-acquisition capital expenditures for the year 2006 aggregated approximately $23.4 million. The amount and timing of our capital expenditures may vary depending on the rate at which we expand and develop our oil and natural gas properties. We may require additional financing for future acquisitions and to refinance our debt before or at its final maturities.

Our capital expenditures for 2005 were $15.0 million, excluding the sale of producing properties, the majority of which was allocated to drilling new wells at proved undeveloped locations and re-completing existing wells. During the year ended December 31, 2004, we acquired WG Energy for $82.6 million and had capital expenditures related to our properties of $5.9 million. In 2003, our capital expenditures were $5.3 million, including $5.1 million in development costs and $202,000 in exploration costs.

Although we cannot provide any assurance, assuming successful implementation of our strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe that borrowings available under our credit facility, the balance of our unrestricted cash and cash flows from operations will be sufficient to satisfy our budgeted capital expenditures, working capital and debt service obligations for the foreseeable future. The actual amount and timing of our future capital requirements may differ materially from our estimates as a result of, among other things, changes in product pricing and regulatory, technological and competitive developments. Sources of additional financing available to us may include commercial bank borrowings, vendor financing and the sale of equity or debt securities. We cannot provide any assurance that any such financing will be available on acceptable terms or at all.

The table below sets forth our contractual cash obligations as of December 31, 2006, which are obligations during the following years:

	2007	2008-2009	2010-11	and after
		(in thousands)		
Contractual Cash Obligations				
Long-term debt	$	$ 28,396	$ 103,000	$
Operating leases	1,114	361	37	
Capital leases				
Purchase obligations				
Total contractual cash obligations	$ 1,114	$ 28,757	$ 103,037	$

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QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The carrying amounts reported in our consolidated balance sheets for cash and cash equivalents, trade receivables and payables, installment notes and variable rate long-term debt approximate their fair values.

Interest Rate Risk

We are exposed to changes in interest rates. Changes in interest rates affect the interest earned on our cash and cash equivalents and the interest rate paid on our borrowings, other than our 11 $^{1}/2$% senior notes. We have not used interest rate derivative instruments to manage our exposure to interest rate changes.

Commodity Price Risk

Our revenue, profitability and future growth depend substantially on prevailing prices for oil and natural gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. Lower prices may also reduce the amount of oil and natural gas that we can economically produce. We currently sell most of our oil and natural gas production under market price contracts.

To reduce exposure to fluctuations in oil and natural gas prices and to achieve more predictable cash flow, we periodically utilize various derivative strategies to manage the price received for a portion of our future oil and natural gas production. We have not established derivatives in excess of our expected production.

Our derivative positions at December 31, 2006 are shown in the following table:

	Crude Oil (Bbls)				Natural Gas (MMBtu)			
	Floors		Ceilings		Floors		Ceilings	
	Per day	Price	Per day	Price	Per day	Price	Per day	Price
Collars								
2007	1,500	$ 52.67	1,500	$ 73.24	4,177	$ 7.48	4,177	$ 11.58
2008	950	53.69	950	86.08	4,000	6.87	4,000	13.53
Secondary Floors								
2007					4,000	12.00		

Crude oil and natural gas contracts cover each month of 2007 and natural gas secondary floors for 2007 are for April through October. Crude oil contracts and natural gas contracts for 2008 are for January through December. For the fourth quarter of 2006, we had a realized gain from our derivative activities of approximately $228,000.

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BUSINESS AND PROPERTIES

General

We are an independent oil and natural gas company engaged in the acquisition, development, exploitation, exploration and production of oil and natural gas properties, primarily in Texas, Louisiana and Oklahoma. Our producing properties are located in highly prolific basins with long histories of oil and natural gas operations. We have been active in these core areas since our inception in 1987 and have grown through a balanced strategy of acquisitions and development and exploratory drilling. We have completed over 20 acquisitions of producing oil and natural gas properties and related assets for an aggregate purchase price approximating $400 million. Through December 31, 2006, we have drilled or participated in the drilling of 561 oil and natural gas wells, 93% of which were successfully completed and produced hydrocarbons in commercial quantities. Our management team has extensive technical and operating expertise in all areas of our geographic focus.

Our oil and natural gas assets are characterized by a combination of conventional and unconventional reserves and prospects. We have conventional reserves and production in four main onshore locations:

- Electra/Burkburnett, Wichita and Wilbarger Counties, Texas;
- Boonsville, Jack and Wise Counties, Texas;
- Vinegarone, Val Verde County, Texas; and
- Egan, Acadia Parish, Louisiana.

We have unconventional reserves and production in our Barnett Shale play located in Jack and Wise Counties, Texas, where we own interests in approximately 27,700 gross (6,800 net) acres.

In addition, we have positioned ourselves for participation in two emerging resource plays in southwest Texas. We have an exploratory play targeting the Barnett and Woodford Shale formations where we own interests in approximately 84,000 gross (6,600 net) acres. We also have an exploratory play targeting the Wolfcamp formation where we are actively acquiring acreage and have accumulated leases and options covering over 15,000 gross and net acres.

At December 31, 2005, our estimated net proved reserves were 18.8 MMBoe, of which approximately 60% were crude oil, 30% were natural gas, and 10% were natural gas liquids, or NGLs. The PV-10 Value of our proved reserves was approximately $345.5 million based on prices we were receiving as of December 31, 2005, which were $58.63 per Bbl of oil, $35.89 per Bbl of NGLs and $9.14 per Mcf of natural gas. At December 31, 2005, our proved developed reserves comprised 70% of our total proved reserves, and the estimated reserve life for our total proved reserves was approximately 15 years.

We own interests in approximately 2,900 wells and are the operator of leases upon which approximately 1,900 of these wells are located. The PV-10 Value attributable to our interests in the properties we operate represented approximately 86% of our aggregate PV-10 Value as of December 31, 2005. We also own a drilling rig and various gathering systems, a natural gas processing plant, service rigs and a supply company that service our producing properties.

From January 1, 1997 through December 31, 2005, our reserve replacement percentage, through discoveries, extensions, revisions and acquisitions, but excluding divestitures, was 344%. Since January 1, 1997, our historical average finding cost from all sources, exclusive of divestitures, has been $6.27 per Boe. During the year ended December 31, 2006, we drilled or participated in the drilling of 92 wells on our oil and natural gas properties, 80 of which were successfully completed as producing wells, four of which were dry holes and eight of which were either drilling or waiting to be completed at the end of that period.

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Principal Properties

The following is a description of each of our principal properties as of September 30, 2006, together with a general description of our miscellaneous and non-core properties. For information regarding our drilling activities in the fourth quarter of 2006, see *Prospectus Summary Recent Events Fourth Quarter Operations*.

Electra/Burkburnett Area. Our properties in the Electra/Burkburnett Area of north Texas include 26 leases covering 12,190 gross acres. As of September 30, 2006, we owned interests in approximately 1,600 wells in the Electra/Burkburnett Area, of which 503 were active producing wells and 215 were active injection wells.

We drilled more than 134 wells in the Electra/Burkburnett Area from November 1, 2004 through September 30, 2006, and, as of September 30, 2006, 152 drilling locations were booked as proved undeveloped locations. We estimate the average recoverable proved reserves attributable to each infill well remaining to be drilled in the Electra/Burkburnett Area should be approximately 22,000 Bbls of oil per well.

During the nine months ended September 30, 2006, we drilled 61 net wells in the Electra/Burkburnett Area, of which 57 were completed as producing wells and four were in various stages of completion at the end of the third quarter. We own a 100% working interest in and operate all 61 of the wells. The initial net daily production from wells drilled and completed during the nine months ended September 30, 2006 averaged 26 Bbls of oil. The average cost incurred by us to drill, complete and equip a producing well in our Electra/Burkburnett Area during the nine months ended September 30, 2006 was $126,700.

The Electra Field has produced millions of barrels of crude oil over the past 80 years. Our currently active wells in this field produce through secondary recovery (waterflood) operations. Well spacing has been decreased to two to three acre spacing in most areas to permit the recovery of bypassed oil and to improve waterflood operations.

Since January 1, 2002, a significant number of new infill and injection wells have been drilled on our Electra/Burkburnett Area leasehold, with a 99% success rate.

Approximately 30% of our wells in the Electra/Burkburnett Area are not equipped to gather casinghead gas, and this gas is vented at the wellhead. The remainder of our produced casinghead gas is processed at our 100% owned Electra Gas Plant, which is located approximately three miles northwest of Electra, Texas on lands leased by us. The term of the surface lease on which our Electra Gas Plant is located will continue for so long as the land is used for the Electra Gas Plant. We pay no rental under the terms of this lease. The plant receives approximately 850 Mcf per day of casinghead gas produced from our properties in the area. The gas is processed in a 1,400 Mcf per day capacity refrigeration unit where approximately 163 Bbls of NGLs per day, net to our interest, are extracted and sold. Approximately 250 Mcf per day of residue gas is used for compressor fuel at the plant and the remainder is flared due to a lack of pipeline facilities in the area.

The largest single operating cost in the field historically has been electricity. In an effort to substantially reduce this cost, in November 2005, we installed two natural gas powered field generators to provide electricity for lease operations. The natural gas used to operate the generators is our natural gas that was previously vented or flared, so the installation of the generators has not reduced sales volumes or lease revenues or increased operating costs. We estimate that since the generators have been in full operation, the resulting savings in field electricity costs has been approximately $38,000 per month.

On April 1, 2005, we purchased a drilling rig specifically for the purpose of facilitating our ongoing drilling program in the Electra/Burkburnett Area and have been using this rig and our own crew and equipment to drill from six to eight wells per month in the field. We also use our own personnel and equipment to perform routine maintenance on our properties and typically do not require third party vendor services. We own our own pulling units, earthmoving equipment, tank trucks and other field equipment to ensure availability and facilitate operations in the field. We employ approximately 65 field employees dedicated to our Electra/Burkburnett operations, all of which work out of our field office in the town of Electra.

We sell the crude oil produced from our Electra/Burkburnett area properties to Shell Trading (US) Company at the STUSCO WTI posted price, plus $1.50. For the month of September 2006, the sale price was $62.50 per Bbl.

During the nine months ended September 30, 2006, the aggregate net production attributable to our interest in the Electra/Burkburnett properties was 483,410 Bbls of oil and 34,598 Bbls of NGLs, or 518,008 Boe, and the average daily production for the period was 1,771 Bbls of oil and 127 Bbls of NGLs, or 1,898 Boe per day.

During September 2006, the aggregate net production attributable to our interest in the Electra/ Burkburnett properties was 50,360 Bbls of oil and 4,878 Bbls of NGLs, or 55,238 Boe, and the average daily production for the period was 1,679 Bbls of oil and 163 Bbls of NGLs, or 1,842 Boe per day.

Egan Field. Our Egan Field, located in Acadia Parish, Louisiana, covers an area of approximately 4,400 acres. Over the past 60 years, more than 90 wells have been drilled in the field at depths ranging from 9,000 feet to 12,400 feet.

The Egan Field is a geologically complex domal feature that produces from a number of different formations that are dissected by extensive faulting. This type of heavily faulted geology is typical of Acadia Parish, where a number of similar fields have been productive for several decades.

Over the past five years, we have undertaken a recompletion program in the Egan Field, conducting successful operations in 12 wells, and have identified more than seven additional recompletion opportunities in existing wellbores.

We own interests in approximately 4,367 gross (2,633 net) leasehold acres and ten producing wells in the Egan Field, and are the operator of all such wells. Our average working interest in the Egan Field properties is approximately 83%, with an average net revenue interest of 71%.

For the nine months ended September 30, 2006, the aggregate net production attributable to our interest in the Egan Field properties was 12,380 Bbls of oil and 261 MMcf of natural gas, or 55,884 Boe, and average daily production for the period was 45 Bbls of oil and 956 Mcf of natural gas, or 205 Boe per day.

During September 2006, aggregate net production attributable to our interest in the Egan Field properties was 1,088 Bbls of oil and 26 MMcf of natural gas, or 5,351 Boe, and our average daily production for the period was 37 Bbls of oil and 853 Mcf of natural gas, or 178 Boe per day.

Boonsville Area. The Boonsville Area is located in the Fort Worth Basin of north central Texas in Jack and Wise Counties. Our leasehold in the area covers approximately 9,950 gross acres lying within the much larger Boonsville Field, which includes several hundred thousand acres.

Our properties in Jack and Wise Counties are comprised of two discrete subsets: the shallow gas zones and the Barnett Shale acreage. Because a considerable portion of our leasehold in the area is segregated with respect to rights above and below the Marble Falls formation, a prominent geologic marker in the area, and our substantially undeveloped Barnett Shale acreage (which lies below the Marble Falls) represents a distinct property requiring drilling, completion and production techniques quite dissimilar from the shallow gas producing zones, we treat our Barnett Shale acreage as a separate major property. We consider the Boonsville Area to include only the properties described herein as the shallow gas zones. Our Barnett Shale acreage is discussed separately below.

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Our oil and natural gas production from the Boonsville Area is derived principally from sands found at depths ranging from 3,800 feet to 6,100 feet. We own working interests in 88 wells producing from these shallow gas zones and operate all but one of such wells.

We own and operate an extensive gas gathering system in the field which gathers gas solely from our wells. The gas is compressed in the field through compression facilities also owned by us, and then is delivered into a system owned and operated by a third party for delivery to the Chico gas processing plant, where the natural gas is processed for the extraction of NGLs. We currently receive 85% of both the residue gas and the NGLs attributable to our share of delivered volumes.

During the nine months ended September 30, 2006, the aggregate net production attributable to our working interests in the Boonsville shallow gas properties (above the Marble Falls) was 12,442 Bbls of oil, 318 MMcf of natural gas and 64,400 Bbls of NGLs, or 130,446 Boe, and average daily production for the period was 46 Bbls of oil, 1,166 Mcf of natural gas and 236 Bbls of NGLs, or 476 Boe per day.

During September 2006, aggregate net production attributable to our interest in the Boonsville shallow gas properties was 984 Bbls of oil, 33,196 Mcf of natural gas and 7,126 Bbls of NGLs, or 13,643 Boe, and the average daily production for the period was 33 Bbls of oil, 1,107 Mcf of natural gas and 238 Bbls of NGLs, or 455 Boe per day.

We have drilled and successfully completed two wells since our acquisition of WG Energy in 2004. We own a 74% working interest in and operate both wells. Currently, there are 20 drilling locations identified as proved undeveloped locations. We believe that additional wells, not currently identified as proved undeveloped locations, will eventually be drilled to test the shallow gas zones underlying our Boonsville properties. We are also actively pursuing a workover program in our existing wells to maximize production and take advantage of opportunities in other potentially productive zones in existing well bores that present attractive recompletion targets.

Barnett Shale Acreage. We own leases covering approximately 27,700 gross (6,800 net) acres of Barnett Shale rights in the Fort Worth Basin of north central Texas, all of which are held by production from wells completed in the shallow gas zones. The Fort Worth Basin Barnett Shale play currently is the largest natural gas play in Texas and one of the leading natural gas plays in the United States. Our Fort Worth Basin Barnett Shale acreage lies in the Boonsville Area of Jack and Wise Counties, Texas, below the Marble Falls geologic marker at depths ranging from 6,500 feet to 8,500 feet and is, for the most part, undeveloped.

The core area of the play is in Denton, Wise and Tarrant Counties, lying just to the east-southeast of our acreage in Jack and Wise Counties. The most productive wells in the Barnett Shale play are wells that have been drilled horizontally. The average cost of drilling and completing a horizontal well to the Barnett Shale is approximately $2.6 million.

We are a party to two separate agreements covering our Barnett Shale acreage position in the Fort Worth Basin:

Approximately 3,500 gross acres are subject to a Participation Agreement with Devon Energy Corporation in which we have the right to participate with a 36% working interest in each well proposed to be drilled on the contract area. The agreement is on a drill-to-earn basis, which means that Devon can earn a 50% working interest and a 40% net revenue interest in a particular lease by drilling and paying its proportionate share of the costs of a well on lands covered by the lease. This agreement includes a continuous drilling obligation, requiring Devon to commence a new well within 120 days after the filing of a completion report on the preceding well, failing which Devon s right to earn under the agreement will terminate, and Devon s interests in undrilled acreage will revert to us. Through September 30, 2006, six horizontal wells have been drilled under the agreement and completed as commercially productive in the Barnett Shale.

Approximately 23,500 gross acres are committed to an agreement with EOG Resources, Inc. In April 2004, we entered into a purchase and sale agreement with EOG, under which EOG purchased from us an undivided 50% working interest and a 40.6% net revenue interest in certain oil and natural gas leases comprising a portion of our Barnett Shale acreage. After giving effect to the sale to EOG, we retained a 23.9% working interest in the subject leases. Currently, our net revenue interest in our Barnett Shale acreage subject to the EOG Agreement is approximately 18%. Through September 30, 2006, EOG has drilled one well on our Barnett Shale acreage, which was completed as a commercially productive well.

During the nine months ended September 30, 2006, the aggregate net production attributable to our interest in the currently producing Barnett Shale wells was 3,441 Bbls of oil and 310 MMcf of natural gas, and average daily production for the period was 13 Bbls of oil and 1,137 Mcf of natural gas, or 202 Boe per day.

During September 2006, the aggregate net production attributable to our interest in the Barnett Shale properties was 313 Bbls of oil, 39 MMcf of natural gas and 287 Bbls of NGLs, and the average daily production for the period was 10 Bbls of oil, 1,316 Mcf of natural gas and 10 Bbls of NGLs, or 239 Boe per day.

Although our Fort Worth Basin Barnett Shale acreage has not yet made a substantial contribution to our daily production, we believe that there are more than 325 potential drilling locations on our acreage, with more than 290 of those locations on leasehold subject to the EOG agreement and more than 35 on the Devon acreage block. We currently have four proved, undeveloped drilling locations that have been established by prior drilling. In addition, our ongoing review of seismic data supports 11 additional drilling locations in the EOG block and eight additional drilling locations in the Devon block as of year end 2006.

We continue to acquire and interpret seismic data covering a portion of our Barnett Shale acreage. Currently, we own 35 square miles of 3-D seismic data and expect to acquire an additional 60 square miles of 3-D seismic data during 2007. At September 30, 2006, we owned an interest in nine (gross) Barnett Shale producing wells, two of which are operated by us, six of which are operated by Devon Energy and one of which is operated by EOG.

Vinegarone Field. The Vinegarone Field is located in Val Verde County, Texas, which is in the Big Bend region of South Texas. We own working interests in seven producing wells in the field, none of which are operated by us.

Production from Vinegarone Field is obtained primarily from three distinct horizons at depths ranging from 9,100 feet to 10,100 feet. We own interests in 6,686 gross (1,830 net) leasehold acres in the Vinegarone Field. In most instances, our working interest is 25%, with an average 21.9% net revenue interest, although in one section (Section 49), in which there are two producing wells, our working interest is 43.8% and our net revenue interest is 38.3%.

During the nine months ended September 30, 2006, we participated in the drilling of three wells in the Vinegarone Field, two of which are in the process of being completed and one of which was a dry hole. We have identified three proved undeveloped locations in the field and expect to continue our development of the field over the next two years.

For the nine months ended September 30, 2006, the aggregate net production attributable to our interest in the Vinegarone Field properties was 241 MMcf of natural gas, and the average daily production for the period was 882 Mcf of natural gas, or 147 Boe per day.

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During September 2006, the aggregate net production attributable to our interest in the Vinegarone Field was 26 MMcf of natural gas, and average daily production for the period was 860 Mcf of natural gas, or 143 Boe per day.

Other Properties

In addition to the principal fields and core operating areas, we also own interests in other properties located in Texas, Oklahoma, Mississippi, Louisiana, Kansas, New Mexico, Wyoming, Arkansas and offshore California.

We own a significant number of properties scattered throughout the principal producing basins in Oklahoma and are actively seeking exploration opportunities within these areas.

In Texas, in addition to the Electra/Burkburnett and Boonsville Area properties, we own miscellaneous operated and non-operated interests in 554 producing wells across the state, from the Panhandle down through the Permian Basin to South Texas, and eastward to Louisiana. We also own leasehold interests in approximately 84,000 gross (6,600 net) acres in an exploratory project located in southwest Texas principally targeting the Barnett and Woodford Shales and approximately 15,000 gross and net acres (including options) in another southwest Texas exploration project targeting the Wolfcamp formation.

Nearly 43,000 gross (5,700 net) acres of our leasehold in the southwest Texas Barnett/Woodford project area are subject to a farmout agreement with J. Cleo Thompson, et. al. Under this agreement, Thompson has acquired ten square miles of 3-D seismic data and drilled the Fasken Ranch 34-2H, a horizontal well recently completed in the Woodford Shale. This well is currently producing approximately 400 Mcf per day with net natural gas sales averaging between 30 and 40 Mcf per day. The remaining natural gas production is being re-injected for gas lift purposes. We will have the right to participate for one-half of our interest following the drilling of the next earning well. Our remaining acreage in this play is subject to a third-party joint operating agreement which allows us the right to participate for an approximate 2% working interest in all future drilling proposals located on this acreage.

On our southwest Texas Wolfcamp project, we drilled two 100%-owned wells during the fourth quarter of 2006. We expect to attempt completion of these wells in the first quarter of 2007. We also participated in two gross (0.2 net) exploratory wells in the Arkoma Basin during 2006.

Ownership and Control of Service and Other Supply Assets

We own and control service and supply assets, including a drilling rig, service rigs, a supply company, gathering systems and other related assets. We believe that ownership and use of these assets for our own account provides us with a significant competitive advantage with respect to availability, lead-time and cost of these services. For the 2007 calendar year, approximately 75% of our projected capital expenditures will be in areas serviced by these assets.

Development, Exploitation and Exploration Programs

Development and Exploitation Program. Our future production and performance depends to a large extent on the successful development of our existing reserves of oil and natural gas. We have identified multiple development projects on our existing properties (substantially all of which are located in our core areas), and these projects involve both the drilling of development wells (which includes 445 injection wells) and extension wells. We are lease operator of leases covering approximately 1,943 of the wells in which we own interests, and as such we are able to control expenses, capital allocation and the timing of development activities of these properties. During the nine months ended September 30, 2006, we drilled or participated in the drilling of 66 gross (63.2 net) development wells on our oil and gas properties, 65 of which were either successfully completed as producing wells, were still drilling, or were awaiting completion at the end of that period. Capital expenditures in connection with these activities during this period aggregated approximately $14.4 million.

Another determinant of future performance is the exploitation of existing wells that can be re-completed or otherwise reworked to extract additional hydrocarbons. We have identified 178 projects

involving re-completions of existing wells, all of which involve reserves included in our proved reserves at December 31, 2005. During the nine months ended September 30, 2006, we conducted or participated in recompletion/workover operations on eight of our existing wells, resulting in the reestablishment or enhancement of production from each of these wells. Our capital expenditures in connection with these recompletion operations aggregated approximately $1.7 million.

Exploration Program. A principal component of our strategy to expand our reserves and production includes an exploration program focused on adding long-lived oil and natural gas reserves from our core areas and other resource plays. Since 1987, we have conducted a successful development and exploitation program resulting in the accumulation of significant long-lived oil and natural gas reserves at relatively moderate depths, located principally in our core areas. In 1998, utilizing the knowledge and expertise gained from this effort, we initiated an exploration program by adding exploration professionals to our technical staff. We intend to maintain an exploration focus in our core areas, while remaining opportunistic with respect to other exploration concepts. These additional exploration concepts include pursuing opportunities in tight gas and other unconventional natural gas plays. In our core areas, we own in excess of 131,000 gross (31,900 net) undeveloped leasehold acres (including options), which enhances our competitive exploration position and provides the foundation for future reserve additions. Included in this number are 99,000 gross (21,600 net) undeveloped leasehold acres (including options) in our Wolfcamp, Barnett, and Woodford Shale resource plays located in southwest Texas. We intend to proceed with exploration in these areas.

We have an experienced technical staff, including geologists, landmen, engineers and other technical personnel devoted to prospect generation and identification of potential drilling locations. We seek to reduce exploration risk by exploring at moderate depths that are deep enough to discover sizeable gas accumulations (generally less than 13,000 feet). Our established presence in our core areas has provided our staff with substantial expertise. Many of our exploration plays are based upon seismic data comparisons to our existing producing fields. While we will maintain this focus, we plan to broaden our exposure and be opportunistic in pursuing growth-oriented exploration plays in other basins, primarily on an operated basis. For exploration prospects we generate, we typically will own a greater interest in these projects than our drilling partners, if any, and will operate the wells. As a result, we will be able to influence the areas of exploration and the acquisition of leases, as well as the timing and drilling of each well.

During the nine months ended September 30, 2006, we participated in the drilling of four gross (2.1 net) exploratory wells at a cost of approximately $1.5 million and incurred total capital expenditures of approximately $1.9 million for all exploration activities.

Oil and Natural Gas Reserves

At December 31, 2005, our estimated net proved reserves were 18.8 million Boe, of which 60% was crude oil, 30% was natural gas, and 10% was NGLs, with a PV-10 Value of approximately $345.5 million before income taxes. Our estimated proved developed reserves comprised 70% of our total proved reserves, and our reserve life for total proved reserves was approximately 15 years.

The following table summarizes the estimates of our historical net proved reserves and the related present values of such reserves at the dates shown. The reserve and present value data for our oil and natural gas properties as of December 31, 2005 was prepared by the independent petroleum engineering firms of

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Williamson Petroleum Consultants, Inc. and Forrest A. Garb & Associates. Our management believes that for each $1.00 per Boe increase or decrease in the price of oil and natural gas, the PV-10 Value of our proved reserves at December 31, 2005 would increase or decrease, as the case may be, by $8.7 million.

Estimated quantities of proved reserves and future net revenues therefrom are affected by oil and natural gas prices, which have fluctuated widely in recent years. There are numerous uncertainties inherent in estimating oil and natural gas reserves and their values, including many factors beyond the control of the producer. The reserve data set forth in this report represent only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers, including those used by us, may vary. In addition, estimates of reserves are subject to revisions based upon actual production, results of future development and exploration activities, prevailing oil and natural gas prices, operating costs and other factors, which revisions may be material. The PV-10 Value of our proved oil and natural gas reserves does not necessarily represent the current or fair market value of such proved reserves, and the 10% discount factor may not reflect current interest rates, our cost of capital or any risks associated with the development and production of our proved oil and natural gas reserves. Proved reserves include proved developed and proved undeveloped reserves.

	As of December 31,		
	2003	**2004**	**2005**
Reserve Data:			
Proved developed reserves:			
Oil (MBbls)	2,151	6,198	7,337
Natural gas (MMcf)	26,237	31,048	26,752
Natural gas liquids (MBbls)(1)		1,611	1,396
Total (MBoe)	6,524	12,984	13,192
PV-10 Value (in thousands)	$ 84,781	$ 164,007	$ 245,107
Proved reserves:			
Oil (MBbls)	2,322	10,667	11,199
Natural gas (MMcf)	34,567	38,195	34,234
Natural gas liquids (MBbls)(1)		2,087	1,891
Total (MBoe)	8,083	19,120	18,796
PV-10 Value (in thousands)	$ 104,570	$ 236,201	$ 345,501
Prices used in calculating PV-10 Value:			
$/Bbl (Oil)	29.25	40.25	58.63
$/Mcf	6.17	6.02	9.14
$/Bbl (NGL)		27.56	35.89

(1) Approximately 16.3% of our estimated proved reserves of NGLs at December 31, 2005, result from our equity ownership in the Electra Gas Plant.

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The following is a summary of the standardized measure of discounted net cash flows using methodology provided for in Statement of Financial Accounting Standard No. 69, related to our estimated proved oil and natural gas reserves. For these calculations, estimated future cash flows from estimated future production of proved reserves were computed using oil and natural gas prices as of the end of the period presented. Future development and production costs attributable to the proved reserves were estimated assuming that existing conditions would continue over the economic lives of the individual leases and costs were not escalated for the future. Estimated future income tax expenses were calculated by applying future statutory tax rates (based on the current tax law adjusted for permanent differences and tax credits) to the estimated future pretax net cash flows related to proved oil and natural gas reserves, less the tax basis of the properties involved. For further information regarding the standardized measure of discounted net cash flows related to our estimated proved oil and natural gas reserves for the years ended December 31, 2003, 2004 and 2005, please review note R in the notes to our year-end 2005 financial statements appearing elsewhere in this prospectus.

The standardized measure of discounted future net cash flows relating to our estimated proved oil and natural gas reserves at December 31 is summarized as follows:

	Year ended December 31,		
	2003	**2004**	**2005**
		(in thousands)	
Future cash inflows	$ 281,149	$ 711,781	$ 1,037,337
Future production costs	(70,644)	(247,314)	(336,048)
Future development costs	(9,534)	(36,495)	(45,271)
Future income tax expenses	(69,787)	(136,669)	(219,640)
Future net cash flows	131,184	291,303	436,418
10% annual discount for estimated timing of cash flows	(63,469)	(129,983)	(209,758)
Standardized measure of discounted future net cash flows	$ 67,715	$ 161,320	$ 226,660

In general, the volume of production from oil and natural gas properties declines as reserves are depleted. Except to the extent we acquire properties containing proved reserves or conduct successful exploration and development activities, our proved reserves will decline as reserves are produced. Our future oil and natural gas production is, therefore, highly dependent upon our level of success in finding or acquiring additional reserves.

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Net Production, Unit Prices and Costs

The following table presents certain information with respect to our oil and natural gas production and prices and costs attributable to all oil and natural gas properties owned by us for the periods shown. Average realized prices reflect the actual realized prices received by us, before and after giving effect to the results of our derivative contracts. Our derivative contracts are financial, and our production of oil, natural gas and NGLs, and the average realized prices we receive from our production, are not affected by our derivative contracts.

	Year ended December 31,			Nine months Ended September 30,
	2003	2004	2005	2006
Production volumes:				
Oil (MBbls)	277	178	787	592
Natural gas liquids (MBbls)	5	12	170	103
Natural gas (MMcf)	2,334	1,928	2,681	1,761
Total (MBoe)	671	511	1,405	989
Average realized prices (before effects of derivative contracts):				
Oil (per Bbl)	$ 29.47	$ 37.63	$ 53.75	$ 63.80
Natural gas liquids (per Bbl)	16.94	26.41	36.33	41.89
Natural gas (per Mcf)	5.06	5.69	6.61	6.22
Total per Boe	29.89	35.14	47.16	53.66
Effect of settlement of derivative contracts:				
Oil (per Bbl)	$	$ (4.48)	$ (1.40)	$ (6.34)
Natural gas liquids (per Bbl)				
Natural gas (per Mcf)		.05	(1.04)	(0.10)
Total per Boe		(1.37)	(2.78)	(3.98)
Average realized prices (after effects of derivative contracts):				
Oil (per Bbl)	$ 29.47	$ 33.15	$ 52.35	$ 57.46
Natural gas liquids (per Bbl)	16.94	26.41	36.33	41.89
Natural gas (Per Mcf)	5.06	5.74	5.57	6.12
Total per Boe	29.89	33.77	44.38	49.68
Expenses (per Boe):				
Oil and natural gas production taxes	$ 2.10	$ 2.47	$ 2.36	$ 2.56
Oil and natural gas production expenses	5.26	7.04	11.46	13.38
Amortization of full cost pool	5.64	5.89	8.93	9.63
General and administrative	9.44	12.90	6.13	6.42

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Acquisition, Development and Exploration Capital Expenditures

The following table presents information regarding our net costs incurred in our acquisitions of proved and unproved properties, and our development and exploration activities:

	Year ended December 31,			Nine months Ended September 30,
	2003	2004	2005	2006
		(in thousands)		
Proved property acquisition costs	$	$ 96,819	$ 155	$ 4,483
Unproved property acquisition costs				757
Development costs	5,056	5,173	11,864	14,393
Exploration costs	202	727	1,507	1,896
Total costs incurred	$ 5,258	$ 102,719	$ 13,526	$ 21,529

Finding Costs

The following table sets forth the estimated proved reserves we acquired or discovered, including revisions of previous estimates, during each stated period. In calculating finding costs, we include acquisition costs related to proved and unproved property acquisitions, exploration costs and development costs that resulted in reserve additions.

	Year ended December 31,		
	2003	2004	2005
Proved reserves acquired/discovered (MBoe)	319	13,704	1,323
Total cost per Boe of reserves acquired/discovered	$4.01	$5.85	$11.91

Producing Wells

The following table sets forth the number of productive wells in which we owned an interest as of September 30, 2006. Productive wells consist of producing wells and wells capable of production, including wells awaiting pipeline connections or connection to production facilities. Wells that we complete in more than one producing horizon are counted as one well.

	Gross	Net
Oil	1,927	1,349
Natural gas	268	122
Total	2,195	1,471

Acreage

The following table sets forth our developed and undeveloped gross and net leasehold acreage, including options to acquire leasehold acreage, as of September 30, 2006:

	Gross	Net
Developed	104,199	38,248
Undeveloped	131,563	31,908
Total	235,762	70,156

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Approximately 90% of our net acreage was located in our core areas as of September 30, 2006. Our undeveloped acreage includes leased acres 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 or not such acreage is held by production or contains proved reserves. A gross acre is an acre in which we own an interest. A net acre is deemed to exist when the sum of fractional ownership interests in gross acres equals one. The number of net acres is the sum of the fractional interests owned in gross acres.

Drilling Activities

During the periods indicated, we drilled or participated in drilling the following wells:

	Year Ended December 31,						Nine Months Ended September 30,	
	2003		2004		2005		2006 (1)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development wells:								
Productive	1	0.5	23	16.3	66	58.1	59	58.5
Non-productive			1	0.3			1	0.3
Exploratory wells:								
Productive	3	0.3	1	0.3	1	0.3	2	0.6
Non-productive			4	0.5			2	1.5
Total	4	0.8	29	17.3	67	58.3	64	60.9

(1) Does not include wells drilling or awaiting completion as of September 30, 2006.

Oil and Natural Gas Marketing and Derivative Activities

During the nine months ended September 30, 2006, two purchasers accounted for approximately 73% of our oil and natural gas revenue. Shell Trading-US accounted for $31.8 million, or 60%, and Dynegy (now, Targa Midstream Services, or Targa) accounted for $6.9 million, or 13%, of our oil and natural gas revenue for that period. No other purchaser accounted for 10% or more of our oil and natural gas revenue during the nine months ended September 30, 2006. Our agreement with Shell Trading-US, or STUSCO, which covers all of our north Texas oil production, through June 30, 2006 provided for payment, on a per barrel basis, of a price equal to Koch s posted price for West Texas Intermediate Crude, plus Platt s Trade-month P+ (a fluctuating premium based on refinery demand), minus $1.15. Effective July 1, 2006, we negotiated a new price of STUSCO WTI plus $1.50. For the month of September 2006, the sales price was $62.50 per Bbl. The agreement is on a month-to-month basis and is cancelable by either party upon 30 days prior written notice. Our gas purchase contract with Targa, which expires February 1, 2013, covers our predominately natural gas producing properties located in Jack and Wise Counties, Texas. Under the terms of the contract, Targa takes delivery of our gas in the field and transports the gas to the nearby Chico Plant where it is processed for the extraction of liquefiable hydrocarbons. Targa pays us 85% of the weighted average price received by Targa for the sale of natural gas and natural gas liquids attributable to the gas delivered by us. There are other purchasers in the fields where our production sold to these two purchasers is produced and marketed, and such other purchasers would be available to purchase our production should any of these two purchasers discontinue operations. We have no reason to believe that any such cessation is likely to occur. However, if the Chico Plant were to cease operations, whether for mechanical, financial or other reasons, such cessation could materially and adversely affect our cash flow

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from operations on a temporary basis, until a new purchaser could install the necessary facilities to take delivery of our natural gas production in the area. We have no reason to believe that any such cessation is likely to occur.

To reduce exposure to fluctuations in oil and natural gas prices and to achieve more predictable cash flow, we periodically utilize various derivative strategies to manage the price received for a portion of our future oil and natural gas production. The notional volumes under our derivative contracts do not exceed our expected production. Our derivative strategies customarily involve the purchase of put options to provide a price floor for our production, put/call collars that establish both a floor and a ceiling price to provide price certainty within a fixed range, put/call call collars that establish a secondary floor above the put/call collar ceiling or swap arrangements that establish an index-related price above which we pay the derivative counterparty and below which we are paid by the derivative counterparty. These contracts allow us to predict with greater certainty the effective oil and natural gas prices to be received for our production and benefit us when market prices are less than the strike prices or fixed prices under our derivative contracts. However, we will not benefit from market prices that are higher than the strike or fixed prices in these contracts for our hedged production.

Our derivative positions at December 31, 2006 are shown in the following table:

	Crude Oil (Bbls)				Natural Gas (MMBtu)			
	Floors		Ceilings		Floors		Ceilings	
	Per Day	Price	Per Day	Price	Per Day	Price	Per Day	Price
Collars								
2007	1,500	$ 52.67	1,500	$ 73.24	4,177	$ 7.48	4,177	$ 11.58
2008	950	53.69	950	86.08	4,000	6.87	4,000	13.53
Secondary Floors								
2007					4,000	$ 12.00		

Crude oil and natural gas contracts cover each month of 2007 and natural gas secondary floors for 2007 are for April through October. Crude oil contracts and natural gas contracts for 2008 are for January through December. For the fourth quarter of 2006, we had a realized gain from our derivative activities of approximately $228,000. For the nine months ended September 30, 2006 our average daily production was 2,169 Bbls of oil, 6,452 Mcf of natural gas, and 376 Bbls of NGLs.

Competition

The oil and natural gas industry is highly competitive. We compete for the acquisition of oil and natural gas properties, primarily on the basis of the price to be paid for such properties, with numerous entities including major oil companies, other independent oil and natural gas concerns and individual producers and operators. Many of these competitors are large, well-established companies and have financial and other resources substantially greater than ours. Our ability to acquire additional oil and natural gas properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

Title to Properties

We believe that we have satisfactory title to our properties in accordance with standards generally accepted in the oil and natural gas industry. As is customary in the oil and natural gas industry, we make only a cursory review of title to farmout acreage and to undeveloped oil and natural gas leases upon execution of any contracts. Prior to the commencement of drilling operations, a title examination is conducted and curative work is performed with respect to significant defects. To the extent title opinions or

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other investigations reflect title defects, we, rather than the seller of the undeveloped property, typically are responsible to cure any such title defects at our expense. If we were unable to remedy or cure any title defect of a nature such that it would not be prudent for us to commence drilling operations on the property, we could suffer a loss of our entire investment in the property. We have obtained title opinions or reports on substantially all of our producing properties. Prior to completing an acquisition of producing oil and natural gas leases, we perform a title review on a material portion of the leases. Our oil and natural gas properties are subject to customary royalty interests, liens for current taxes and other burdens that we believe do not materially interfere with the use of or affect the value of such properties.

Facilities

Our executive and operating offices are located at Suite 650, Meridian Tower, 5100 E. Skelly Drive, Tulsa, Oklahoma 74135 which we occupy under a lease with a remaining term ending in June 2008, at an annual rental of $288,728, subject to escalations for taxes and utilities. We also lease a small office in Houston. We believe that our facilities are adequate for our current needs.

Regulation

General. Various aspects of our oil and gas operations are subject to extensive and continually changing regulation, as legislation affecting the oil and gas industry is under constant review for amendment or expansion. Numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding upon the oil and gas industry and our individual members.

Regulation of Sales and Transportation of Natural Gas. The Federal Energy Regulatory Commission, or the FERC, regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. In the past, the federal government has regulated the prices at which natural gas can be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Our sales of natural gas are affected by the availability, ter