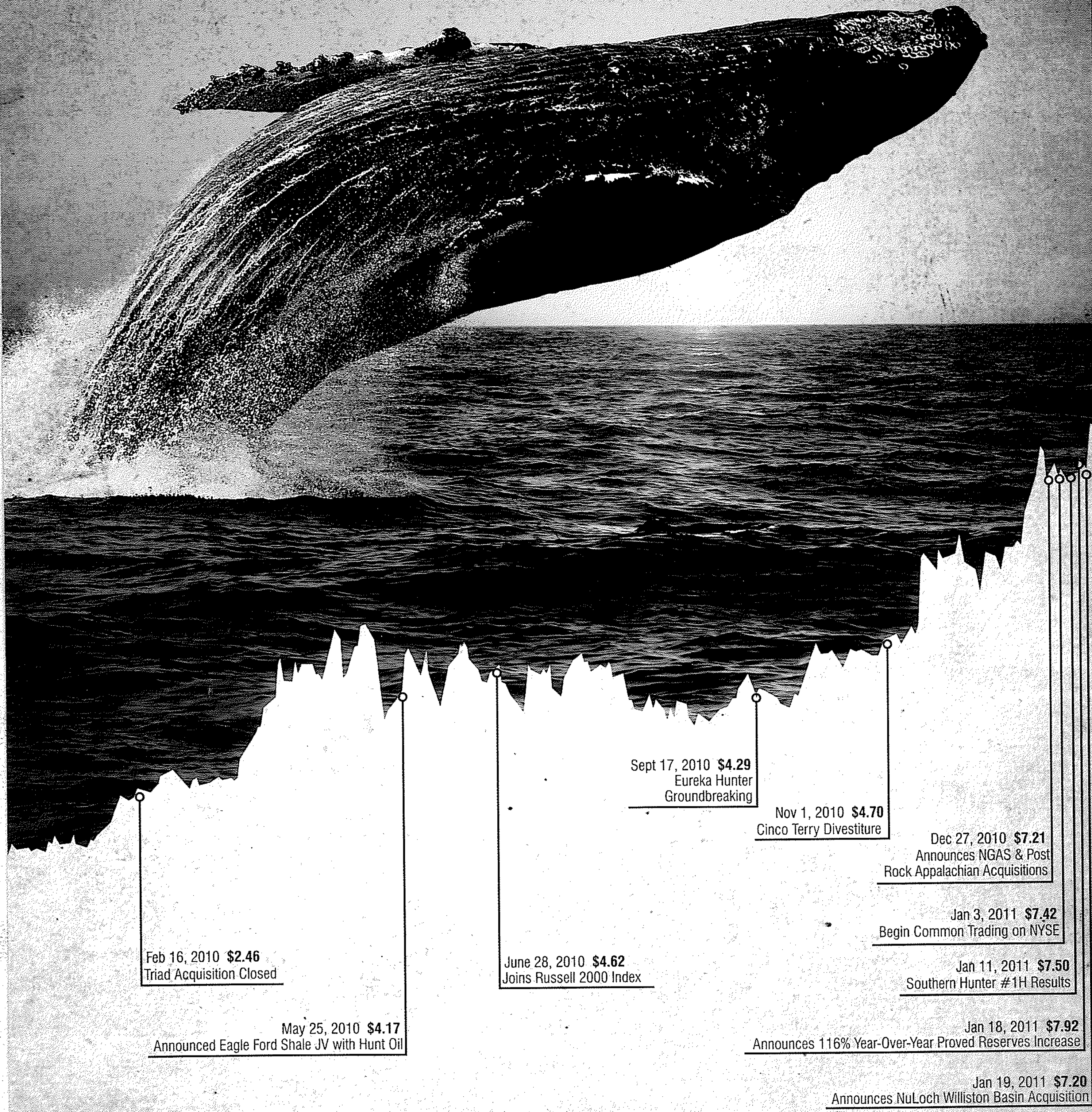
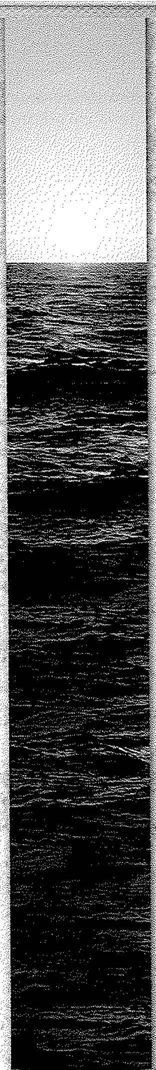
MAGNUM HUNTER
RESOURCES CORPORATION
2010 Annual Report



Reaching New Heights



2010 Significant Events

01.28.2010	Confirmation by U.S. Bankruptcy Court of Triad Energy's Plan of Reorganization
02.16.2010	Final Closing on the Acquisition of Appalachian Basin Focused Triad Energy
03.15.2010	Year-End 2009 Proved Reserves Increase of 99% over Year-End 2008
05.13.2010	120% Increase in 2010 Capital Budget from $25 Million to $55 Million
05.13.2010	Increase in Revolving Credit Facility Borrowing Base to $75 Million
05.25.2010	Joint Exploration Agreement with Hunt Oil Company in Eagle Ford Shale Oil Window
06.08.2010	Redemption of Outstanding $15 Million Series "B" Redeemable Convertible Preferred Stock
06.28.2010	Joins Russell 2000 Index
08.06.2010	Mid-Year 2010 Total Proved Oil & Gas Reserves up 91% from Year-End 2009
09.17.2010	Celebrates Groundbreaking for the Eureka Hunter Gas Pipeline
10.07.2010	Second Joint Venture in the Eagle Ford Shale
11.01.2010	Divestiture of Cinco Terry Property for $21.5 Million
12.17.2010	Commits to Purchase 200 MMcf per Day Capacity Cryogenic Natural Gas Processing Plant for the Eureka Hunter Pipeline System
12.23.2010	Marcellus Shale Development Activity Update - Weese Hunter #1001 Successful
12.27.2010	Announces Agreement To Acquire Appalachian Basin Focused NGAS Resources for $98 Million
12.27.2010	Announces Agreement To Acquire Appalachian Basin Properties for $40 Million
01.03.2011	Common Shares Begin Trading on the New York Stock Exchange
01.11.2011	Eagle Ford Shale Drilling Update - Gonzo Hunter #1-H, Camp Lagunillas #1-H and #2-H, and Southern Hunter #1-H All Producing
01.12.2011	Final Funding of $100 Million in Series C Perpetual Preferred Stock
01.18.2011	Total Proved Reserves at Year-End 2010 increase 116% as Compared to Year-End 2009
01.19.2011	Announces Agreement to Acquire Williston Basin Focused NuLoch Resources for $327 Million (USD)

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Financial and Operations Summary

	2010	2009	2008
Total Revenues	$ 32,723,673	$ 6,843,569	$ 11,589,781
Net Income (Loss)	$ (13,799,929)	$ (15,124,209)	$ (6,886,334)
Preferred Stock Dividends	$ (2,466,679)	$ (25,654)	$ (734,406)
Net Income (Loss) Applicable to Common Stock	$ (16,266,608)	$ (15,149,863)	$ (7,620,740)
Per Share - Diluted	$ (0.25)	$ (0.39)	$ (0.21)
Common Shares Used in Per Share Calculation	$ 63,921,525	$ 38,953,834	$ 36,714,489
Total Assets	$ 248,966,825	$ 66,584,051	$ 61,664,868
Net, Property, Plant and Equipment	$ 232,600,625	$ 46,410,049	$ 45,938,221
Long-Term Debt			
Notes Payable	$ 26,018,615	$ 13,000,000	$ 21,500,000
Series C Convertible Preferred Stock	$ 70,236,400	$ 5,373,750	$ -
Stockholders' Equity	$ 103,321,689	$ 39,317,925	$ 35,078,263
Debt-to-Capitalization Ratio	15%	29%	61%
RESERVES			
Proved Reserves, MMBoe	13.4	6.2	3.1
PV-10, Before Income Taxes ($MM)	$ 177.8	$ 65.6	$ 21.0
Gas Price Used in Reserve Report ($ per MMBtu)	$ 4.37	$ 3.35	$ 5.04
Oil Price Used in Reserve Report ($ per Barrel)	$ 79.43	$ 54.96	$ 40.33
PRODUCTION			
Oil Production, MBbl	316	115.0	111.0
Average Sales Price, $/Bbl (Net of Hedges)	$ 72.41	$ 53.56	$ 86.92
Natural Gas Production, MMcf	952	191	130
Average Sales Price, $/Mcf (Net of Hedges)	$ 5.07	$ 2.46	$ 4.36
Lease Operating Expenses, $/Boe	$ 21.90	$ 26.48	$ 30.42
WELLS / ACREAGE			
Gross Wells	2,262	248	33
Gross Operated Wells	2,082	4	0
Gross Mineral Acreage	348,722	265,904	287,603
Net Mineral Acreage	139,481	49,706	51,065
Miles of Gas Gathering Pipelines	129	0	0

Letter to Shareholders

Last year at this time, in my first letter written to you as your new Chairman and Chief Executive Officer, we were proud of our early accomplishments which included "approaching a $200 million market capitalization." As I write to you today, just one year later, our market capitalization has increased to over $500 million, and pending two acquisitions, our market cap should exceed $1 billion by mid-year. Also, we achieved a milestone early in 2011 as Magnum Hunter's common shares were approved and listed on the NYSE effective January 3.

We have transformed the Company into what I like to describe as a "three legged stool," focused on unconventional resource plays. Our industry has changed over the last five years. We can now drill reservoirs that we never before imagined would be commercially productive. The combination of horizontal drilling and fracture stimulation/completion techniques has truly transformed the way we conduct business. The Eagle Ford Shale of South Texas, the Marcellus, Huron, Weir and Utica Shales of Appalachia, and the Three Forks Sanish and Bakken in the Williston Basin will be the core of Magnum Hunter for the future. Our activities in the Eagle Ford Shale and Williston Basin are exclusively focused on crude oil development. While our production is heavily weighted toward oil and liquids-rich natural gas, I believe it is inevitable that natural gas prices will eventually improve. However, until then, we will focus most of our capital program towards oil and liquids-rich opportunities.

Today we have five new horizontal wells producing in the Eagle Ford Shale of South Texas and three wells drilled and waiting on fracture stimulation. Our foothold in this region began with our acquisition of Sharon Resources in September 2009. Initial well production rates are now exceeding 1,200 barrels of oil equivalent (Boe) per day. Our leasehold position is concentrated in Gonzales and Atascosa counties and includes 51,644 gross acres and 25,074 net acres of land. We have two working joint ventures with Hunt Oil Company of Dallas and GeoSouthern Energy of Houston. Our game plan for 2011 is to drill approximately one and one-half wells per month with a $65 million capital expenditure budget.

In the Appalachia division, our focus is on the Marcellus Shale. This is one of the most attractive shale plays in the United States with one of the lowest break-even cost structures; therefore, it will remain attractive throughout the commodity cycle. Magnum Hunter has drilled five horizontal Marcellus wells to-date, three of which are on production and two that are waiting on fracture stimulation. Initial well production rates have exceeded 7 million cubic feet equivalent (MMcfe) per day. Magnum Hunter currently controls 56,595 net acres and continues to expand our ownership position in the Marcellus. Internal rates of return, even with natural gas at $4.00 to $5.00 per Mcf, range from 80% to 200%. This is due to the liquids-rich nature of the gas stream. We completed a $40 million acquisition of existing wells and leasehold in December 2010 and January 2011, which further expands our ownership interest into Lewis and Wetzel counties in West Virginia.

In late December, we announced an agreement to acquire Appalachian Basin focused NGAS Resources, Inc. for approximately $98 million in common stock and assumed liabilities. Magnum Hunter agreed to acquire NGAS for $0.55 per share with a fixed exchange ratio of 0.0846 based on an agreed Magnum Hunter stock price of $6.50 per share. Everything is on schedule to close the NGAS acquisition by mid-April 2011.

NGAS Highlights

- Proved reserves of 66 Bcfe at year-end 2010
- 74% natural gas (1,200 Btu) and 65% proved developed producing
- Long-lived with a 23 year reserve life
- Over 1,400 producing wells (85% operated)
- Daily production exceeding 9 MMcfe
- More than 300,000 net leasehold acres
- 68% undeveloped with over 2,400 low risk horizontal drilling locations
- Historical drilling success rate of 98%

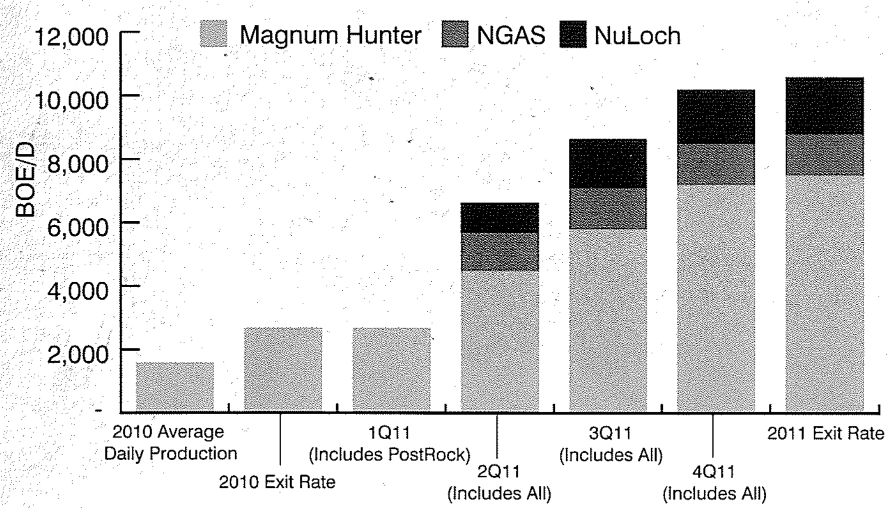
On January 19, 2011, Magnum Hunter signed an agreement to acquire Williston Basin focused NuLoch Resources, Inc. in an all common stock transaction valued at $327 million (USD). NuLoch is a Canadian public company based in Calgary and trades on the Toronto Stock Exchange. Magnum Hunter agreed to acquire NuLoch for $2.50 (Canadian) per share with a fixed exchange ratio of 0.3304, which was based on the seven-day volume weighted average price of Magnum Hunter's common stock prior to the announcement of $7.63 per share.

NuLoch Highlights

- Proved reserves of 5 million Boe (85% crude oil)
- Estimated probable reserves of 3 million Boe
- Nine year reserve life
- Current production capacity of 1,550 Boe per day
- 69,900 net acres in the Williston Basin
- 50,680 net acres located in Alberta
- 267 net identified Williston Basin drilling locations
- Six drilling rigs currently running

We are on track to close this transaction prior to the end of April 2011. We are excited that the senior management team of NuLoch including their CEO, Glenn Dawson, has agreed to stay on and lead the new technical group managing our Rocky Mountain/Williston Basin division.

Our Company's production growth will come from a combination of acquisitions and through successful drilling. We anticipate a daily production growth profile second to none in fiscal 2011 as shown on the graph below.



Magnum Hunter's productive well count has jumped from 248 to 2,262 wells, 92% operated. Our gross and net mineral acreage inventory, which we control for future drilling opportunities, increased to 348,722 and 139,481 acres, respectively, before counting the significant acreage positions of both NGAS and NuLoch.

Another measure of operational success is our ability to drive down our production cost, which is the cost to lift a barrel or mcf out of the ground. In 2008, our average lifting cost was $35.78 per barrel. We reduced this to $29.89 per barrel in 2009 and to $26.75 per barrel in 2010. This operating measure is extremely important. If we can continue to drive these costs down and commodity prices improve as they have done in 2010 with respect to crude oil, then our net operating margins improve dramatically. Our 2011 business plan includes a $150 million capital expenditure program, before capital needs of our two pending acquisitions, NGAS and NuLoch. We anticipate another $80 million of capital expenditures once these two transactions are closed which would bring the total capital expended for the year up to approximately $230 million. This is greater than our Company's entire market capitalization this time last year!

Our Eureka Hunter Pipeline system which covers 129 miles in northwest West Virginia, originally came to us through the Triad acquisition in February 2010. We continue to grow this system as we expand our footprint in this region. A total of 14 miles of new 20-inch pipe has now been laid that has the capacity to move 200 to 300 million cubic feet of natural gas per day. The expanded system went operational in December 2010. We have also ordered a new 200 million cubic feet per day cryogenic processing plant (currently under construction) for installation in this region and to be tied to the pipeline system. I am pleased to report that we have recently expanded our management team at Eureka Hunter to include Dan McCormick as Senior Vice President – Operations for this division.

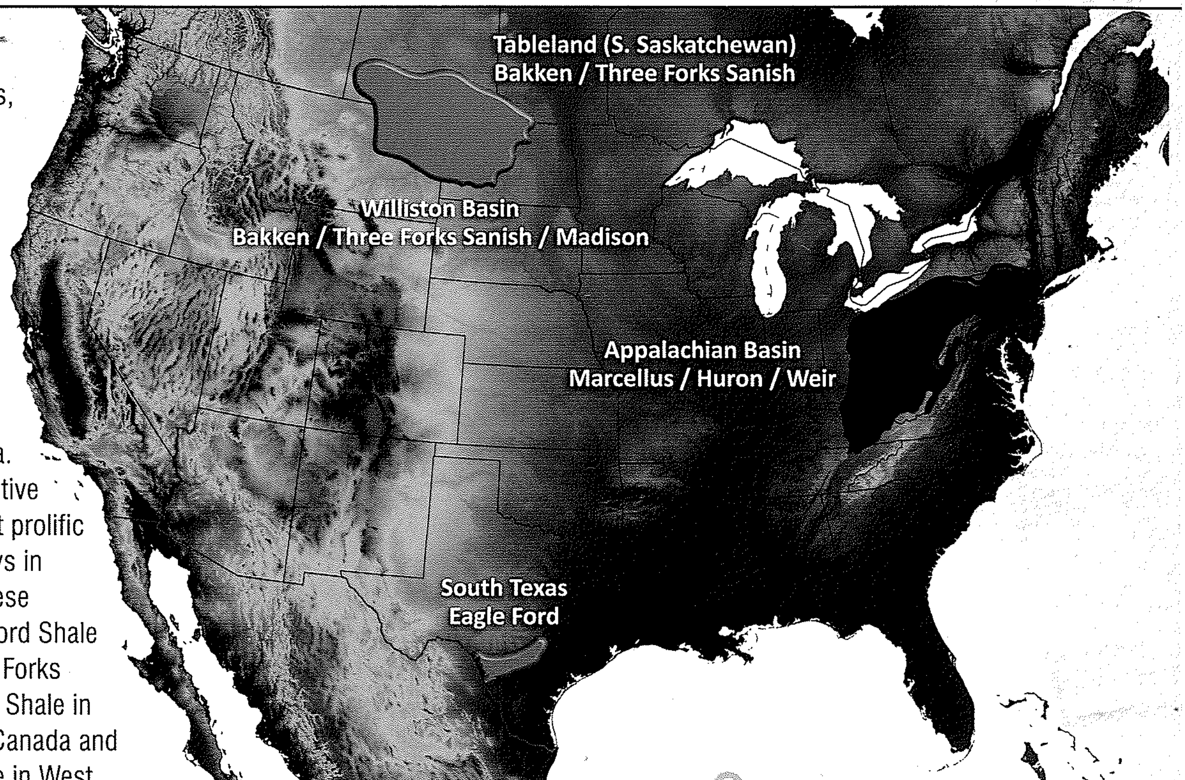
The theme of our 2010 annual report is "Reaching New Heights." Share price improvement in 2010 was an outstanding 365%, up from $1.55 per share at year-end 2009 to $7.20 per share at year-end 2010. The number of Wall Street equity research analysts that follow Magnum Hunter increased from four at year-end 2009 to eighteen at year-end 2010. This expanded research coverage contributed to our trading volume reaching 788,000 shares per day on the NYSE. Our strategic game plan is working. Our primary focus remains on shareholder returns. We are extremely excited about our growth prospects for 2011 that are well defined and in progress. The foundation we have been forming has been built, and your management team will deliver the results that you expect from this significantly expanded asset base. As always, we appreciate your support and vote of confidence.

Sincerely,

Gary C. Evans

Gary C. Evans
Chairman and Chief Executive Officer

Areas of Operation



Magnum Hunter Resources acquires, develops and produces oil and natural gas from unconventional resource properties in the United States and, upon completion of the NuLoch acquisition, Canada. The Company is active in three of the most prolific shale resource plays in North America. These include the Eagle Ford Shale in Texas, the Three Forks Sanish and Bakken Shale in North Dakota and Canada and the Marcellus Shale in West Virginia and Ohio.

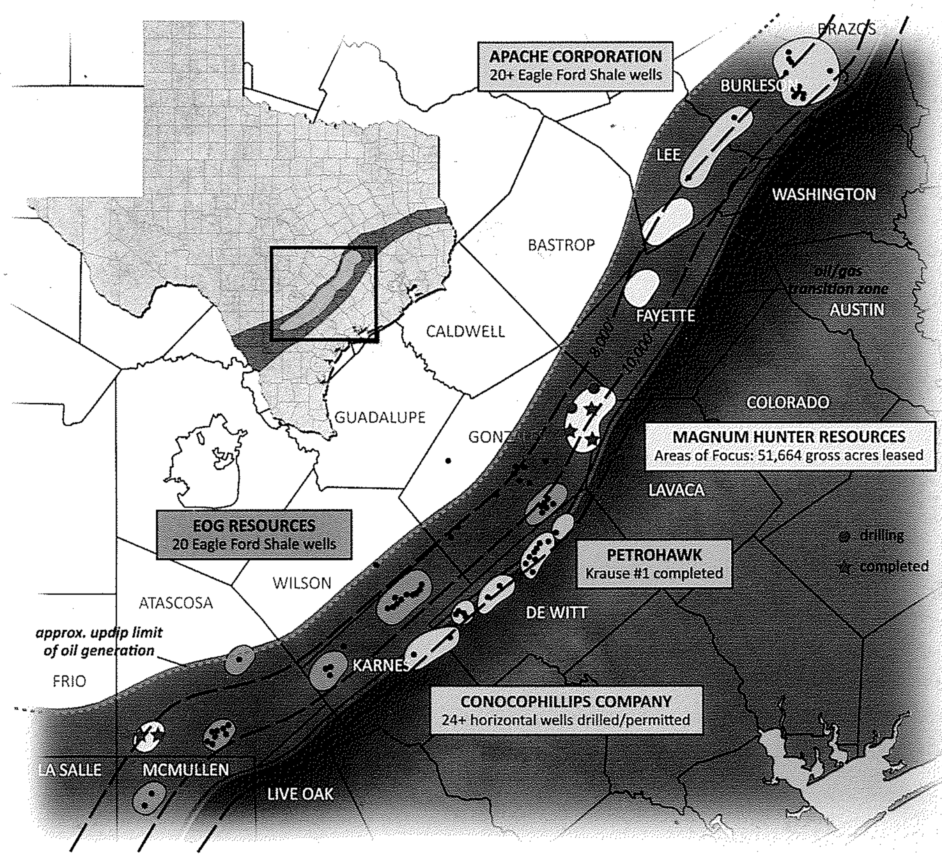
"Magnum Hunter focuses on unconventional resource plays with an oil or liquids-rich focus."

Magnum Hunter's strategy consists of exploiting its inventory of lower-risk drilling locations and acquiring long-lived proved reserves with significant exploitation and development opportunities. Pursuing this strategy, the Company grew its reserves to 13.4 million barrels of oil equivalent (Boe) at year-end 2010, a 116% increase over 2009. Since year-end, Magnum Hunter has announced two acquisitions, which will add 19.0 million Boe of reserves in the Williston and Appalachian Basins, bringing the Company's Pro Forma proved reserves to 32.4 million Boe of which 49% are proved developed producing.

The Eagle Ford Shale

The Eagle Ford Shale, a Cretaceous-aged shale, exists at depths of 7,500 feet to more than 14,000 feet and ranges in thickness of less than 100 to more than 400 feet. The Eagle Ford Shale is productive within the majority of the trend, producing both oil and natural gas.

Magnum Hunter has amassed approximately 25,000 net acres in the Eagle Ford Shale play through leasing and multiple joint venture agreements. Magnum Hunter's Eagle Ford Shale play is located in the oil window of the trend with original oil in place of 20 to 40 million barrels of oil per section.



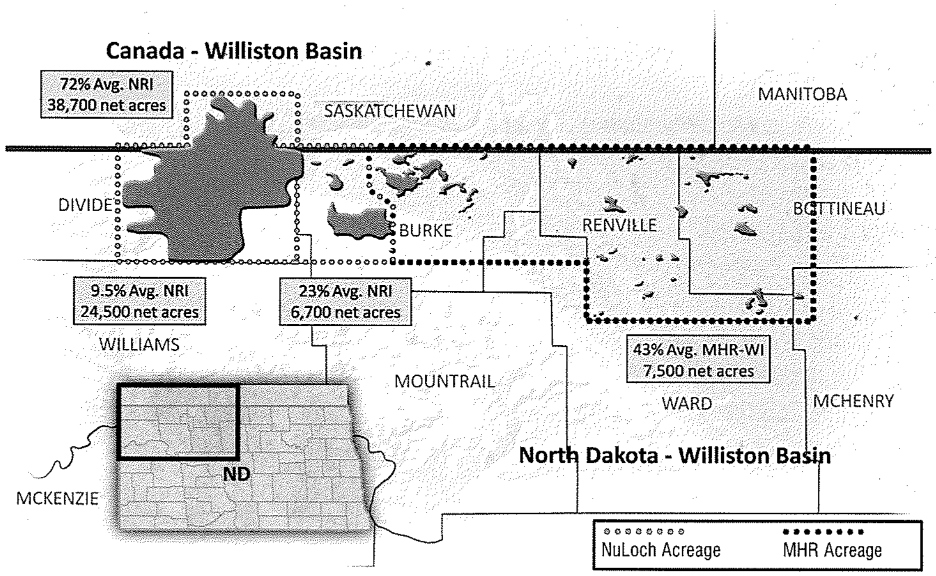
Effective development of the play depends on optimization of horizontal drilling and multi-stage reservoir stimulation. Longer horizontal laterals and the latest fracture stimulation technology have increased the estimated ultimate recovery (EUR) and stabilized production rates from each well drilled. Initial production rates in the "oil window" depend on the gas oil ratio (GOR), whereby an increasing GOR exhibits a higher initial production rate with a steeper decline. Rock properties and fluid characteristics also can enhance deliverability and EURs.

At year-end 2010, Magnum Hunter has 967 thousand Boe of proved reserves in the Eagle Ford Shale and approximately 100 horizontal Eagle Ford Shale drilling locations in inventory. Based upon recent production histories, estimated ultimate recovery is anticipated to be in the range of 500 thousand Boe per well. Magnum Hunter has budgeted $65 million in 2011 to drill 14 gross (8 net) horizontal wells targeting the Eagle Ford Shale. The Company is focused in the up-dip oil trend of the Eagle Ford Shale between 8,000 and 11,000 feet, which provides better economics with lower drilling cost and higher commodity prices than the natural gas play.

> "The Eagle Ford Shale is one of the country's hottest new shale plays."

The Williston Basin

The Williston Basin is spread across North Dakota, Montana and parts of southern Canada. The United States portion of the basin encompasses approximately 143,000 square miles and produces oil and natural gas from numerous horizons including the Madison, Bakken, Three Forks Sanish and Red River formations. The Bakken formation, a Devonian-age shale, is estimated to contain up to 4.3 billion barrels of recoverable crude oil making it the largest continuous crude oil accumulation ever assessed by the United State Geological Survey (USGS Report dated April 2008). The Bakken formation is generally found at vertical depths of 9,000 to 10,500 feet, and below the Lower Bakken Shale lies the Three Forks Sanish formation, which also contains reservoir rock. Crude oil production from the Bakken Shale and Three Forks Sanish reservoirs is made possible through the combination of advanced horizontal drilling and fracture stimulation technology.

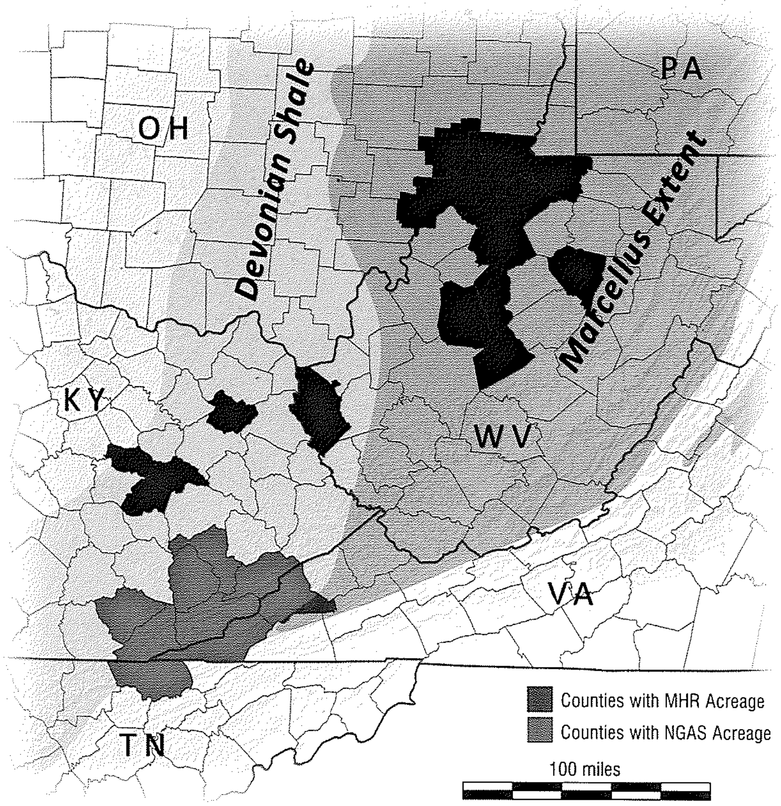


At December 31, 2010, Magnum Hunter owned interests in 15 fields and approximately 7,500 net acres in the Williston Basin with proved reserves of 2.5 million Boe. The Company's Williston Basin position changed dramatically in January 2011, when Magnum Hunter announced an agreement to acquire NuLoch Resources, Inc., a Canadian public oil and natural gas producer located in Calgary, Alberta. With NuLoch, Magnum Hunter is adding more than 122,000 net acres in the U.S. and Canada, 71,000 of which are in the evolving Bakken-Three Forks Sanish formations of the Williston Basin. Proved reserves at December 31 are 5.0 million Boe based on SEC pricing. Proved plus probable reserves are 7.9 million Boe. At December 31, 2010, Magnum Hunter was producing approximately 392 Boe per day in the Williston Basin. The NuLoch acquisition will initially add over 1,000 Boe per day, bringing production in the Williston Basin to greater than 1,350 Boe per day.

> "We've established a two-pronged attack of Middle Bakken and Three Forks Sanish which doubles the reserve and production potential of the oil-rich Williston Basin resource play."

Appalachian Basin / Marcellus Shale

The Appalachian Basin spans more than 180,000 square miles from New York to Alabama and is considered the most mature oil and gas producing region in the United States. The advent of horizontal drilling and the evolution of fracture stimulation technology has led to a renaissance in the basin with the development of the Marcellus Shale, one of the country's premier economic shale gas reservoirs. This Devonian age shale is a black, organic-rich shale deposit productive at depths between 5,500 and 6,000 feet and ranges in thickness from 50 to 80 feet. Gas produced from the Marcellus Shale area enjoys a price premium for both the high liquid content and proximity to the energy-consuming regions of the mid-Atlantic and northeastern United States.

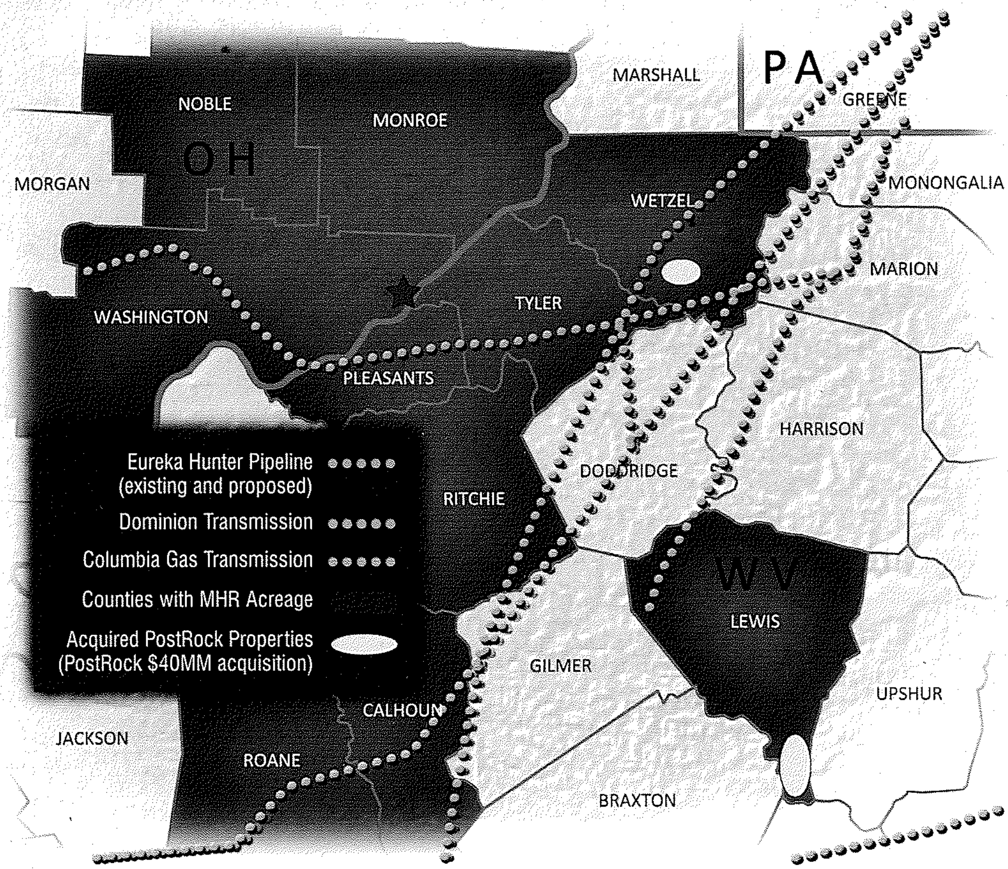


Since February 2010, Magnum Hunter has completed three acquisitions of properties in the Appalachian Basin resulting in more than 90,000 net acres in the Appalachian Basin including approximately 56,595 net acres overlying the core Marcellus Shale area. Approximately 75% of Magnum Hunter's acreage is held by production. The Company's shallow production comes from the Berea, Macksburg 500 Sand, Devonian Shale and the Clinton/Medina Sands, and potential exists for the Trenton-Black River and Huron formations. In addition to its Marcellus Shale development, Magnum Hunter has significant enhanced waterflood oil recovery operations in West Virginia.

> "The Marcellus has one of the lowest break-even price levels of all the shale plays and will remain attractive throughout the commodity cycle."

At year-end 2010, proved reserves in the Appalachian Basin are 7.2 million Boe, 45% oil and approximately 50% proved developed producing. Magnum Hunter operates 2,048 wells in the basin and exited 2010 producing approximately 1,575 Boe per day. In 2011, Magnum Hunter will drill a minimum of 15 horizontal wells in the Marcellus Shale from an inventory of more than 439 identified drilling locations. The 2011 drilling budget for the Appalachian Basin is approximately $60 million.

Midstream: Eureka Hunter Pipeline



Development of the Marcellus Shale is contingent upon access to oilfield services and transportation to the interstate pipeline grid. Access to a pipeline system is often a deciding factor on drilling and production decisions. Magnum Hunter owns the Eureka Hunter Pipeline system, consisting of approximately 182 miles

> "Access to a pipeline system is often a deciding factor on drilling and production decisions."

of pipeline, gathering and rights-of-way located in the Marcellus Shale in northern West Virginia. The Company is currently constructing the second phase of a new 20-inch high-pressure pipeline with 200 to 300 MMcf per day of throughput capacity. The first section of the pipeline was turned to sales on December 22, 2010. The next section of the pipeline is expected to be completed by March 31, 2011. Magnum Hunter will transport significant quantities of Company-produced natural gas as well as third-party gas through its subsidiary Eureka Hunter Pipeline. The Company has budgeted $25 million in 2011 for the completion of Phase I of the project, which consists of approximately 16 miles of primary pipeline and 20 miles of laterals. Additionally, Magnum Hunter has contracted to build a 200 MMcf per day cryogenic processing plant to service the Eureka Hunter Pipeline. The plant will be funded with project financing and is expected to be operational in mid-2012.

THIS DOCUMENT REPRESENTS A COMPOSITE OF THE FORM 10-K FOR THE FISCAL YEAR ENDED DECEMBER 31, 2010 FILED ON FEBRUARY 18, 2011 AND AN AMENDMENT TO THE FORM 10-K FILED ON MARCH 15, 2011.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2010

Commission file number: 001-32997

MAGNUM HUNTER RESOURCES CORPORATION

Magnum Hunter Resources Corporation

(Name of registrant as specified in its charter)

Delaware	**86-0879278**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

777 Post Oak Boulevard, Suite 650, Houston, Texas 77056

(Address of principal executive offices, including zip code)

Registrant's telephone number including area code: (832) 369-6986

Securities registered under Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
$0.01 par value Common Stock	NYSE
10.25% Series C Cumulative Perpetual Preferred Stock	NYSE Amex

Securities registered under Section 12(g) of the Act:

None

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐ Accelerated filer ☑ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

State the aggregate market value of voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter: $276,042,143.

As of February 16, 2011, 76,462,082 shares of the registrant's common stock were issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Documents incorporated by reference: Portions of the registrant's notice of annual meeting of shareholders and proxy statement to be filed pursuant to Regulation 14A within 120 days after the registrant's fiscal year end of December 31, 2010 are incorporated by reference into Part III of this Form 10-K.

Magnum Hunter Resources Corporation

2010 Annual Report on Form 10-K

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CAUTIONARY NOTICE

The statements and information contained in this annual report on Form 10-K that are not statements of historical fact, including all of the estimates and assumptions contained herein, are "forward looking statements" as defined in Section 27A of the Securities Act of 1933, as amended, referred to as the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, referred to as the Exchange Act. These forward-looking statements include, among others, statements, estimates and assumptions relating to our business and growth strategies, our oil and gas reserve estimates, our ability to successfully and economically explore for and develop oil and gas resources, our exploration and development prospects, future inventories, projects and programs, expectations relating to availability and costs of drilling rigs and field services, anticipated trends in our business or industry, our future results of operations, our liquidity and ability to finance our exploration and development activities, market conditions in the oil and gas industry and the impact of environmental and other governmental regulation. In addition, with respect to our pending acquisitions of NGAS Resources, Inc., referred to as NGAS, and NuLoch Resources Inc., referred to as NuLoch, forward-looking statements include, but are not limited to, statements regarding the expected timing of the completion of the proposed transactions; the ability to complete the proposed transactions considering the various closing conditions; the benefits of such transactions and their impact on the Company's business; and any statements of assumptions underlying any of the foregoing. In addition, if and when either proposed transaction is consummated, there will be risks and uncertainties related to the Company's ability to successfully integrate the operations and employees of the Company and the acquired business. Forward-looking statements generally can be identified by the use of forward-looking terminology such as "may", "will", "could", "should", "expect", "intend", "estimate", "anticipate", "believe", "project", "pursue", "plan" or "continue" or the negative thereof or variations thereon or similar terminology.

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

- adverse economic conditions in the United States and globally;
- difficult and adverse conditions in the domestic and global capital and credit markets;
- changes in domestic and global demand for oil and natural gas;
- volatility in the prices we receive for our oil and natural gas;
- the effects of government regulation, permitting and other legal requirements;
- future developments with respect to the quality of our properties, including, among other things, the existence of reserves in economic quantities;
- uncertainties about the estimates of our oil and natural gas reserves;
- our ability to increase our production and oil and natural gas income through exploration and development;
- our ability to successfully apply horizontal drilling techniques and tertiary recovery methods;
- the number of well locations to be drilled, the cost to drill and the time frame within which they will be drilled;
- drilling and operating risks;
- the availability of equipment, such as drilling rigs and transportation pipelines;
- changes in our drilling plans and related budgets;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity; and
- other factors discussed under "Risk Factors" in Item 1A of this report.

With respect to the Company's pending acquisitions, factors, risks and uncertainties that may cause actual results, performance or achievements to vary materially from those anticipated in forward-looking statements include, but are not limited to, the risk that either proposed transaction will not be consummated; failure to satisfy any of the conditions to either proposed transaction, such as in the case of the NGAS transaction the inability to obtain the requisite approvals of the NGAS shareholders and the Supreme Court of British Columbia, or in the case of the NuLoch transaction, the inability to obtain the requisite approvals of NuLoch's shareholders, the Company's shareholders and the Court of Queen's Bench of Alberta; adverse effects on the market price of our common stock or on our operating results because of a failure to complete either proposed transaction; failure to realize the expected benefits of either proposed transaction; negative effects of announcement or consummation of either proposed transaction on the market price of our common stock; significant transaction costs and/or unknown liabilities; general economic and business conditions that affect the companies following the proposed transaction; and other factors.

These factors are in addition to the risks described in the "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" sections of this document. Most of these factors are difficult to anticipate and beyond our control. Because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by such statements. You are cautioned not to place undue reliance on forward-looking statements contained herein, which speak only as of the date of this document. Other unknown or unpredictable factors may cause actual results to differ materially from those projected by the forward-looking statements. Unless otherwise required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. We urge readers to review and consider disclosures we make in this and other reports that discuss factors germane to our business. See in particular our reports on Forms 10-K, 10-Q and 8-K subsequently filed from time to time with the Securities and Exchange Commission, which we refer to as the SEC.

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a description of the meanings of some of the oil and natural gas industry terms used in this report.

bbl	Stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.
bcf	Billion cubic feet of natural gas.
boe	Barrels of crude oil equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.
boe/d or boepd	boe per day.
Completion	The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.
Condensate	Hydrocarbons which are in the gaseous state under reservoir conditions and which become liquid when temperature or pressure is reduced. A mixture of pentanes and higher hydrocarbons.
Development well	A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.
Drilling locations	Total gross locations specifically quantified by management to be included in the Company's multi-year drilling activities on existing acreage. The Company's actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, drilling results and other factors.
Dry hole	A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or gas well.
EUR	Estimated ultimate recovery.
Exploratory well	A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.
Field	An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.
Formation	An identifiable layer of rocks named after its geographical location and dominant rock type.
Lease	A legal contract that specifies the terms of the business relationship between an energy company and a landowner or mineral rights holder on a particular tract of land.
Leasehold	Mineral rights leased in a certain area to form a project area.
mbbls	Thousand barrels of crude oil or other liquid hydrocarbons.
mbblspd	Thousand barrels of crude oil or other liquid hydrocarbons per day.

mboe	Thousand barrels of crude oil equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.
mboepd	Thousand barrels of crude oil equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids, per day.
mcf	Thousand cubic feet of natural gas.
mcfpd	Thousand cubic feet of natural gas per day.
mcfe	Thousand cubic feet equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.
mcfepd	Thousand cubic feet equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids, per day.
mmbbls	Million barrels of crude oil or other liquid hydrocarbons.
mmblspd	Million barrels of crude oil or other liquid hydrocarbons per day.
mmboe	Million barrels of crude oil equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.
mmboepd	Million barrels of crude oil equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids, per day.
mmbtu	Million British Thermal Units.
mmbtupd	Million British Thermal Units per day
mmcf	Million cubic feet of natural gas.
mmcfpd	Million cubic feet of natural gas per day.
Net acres, net wells, or net reserves	The sum of the fractional working interests owned in gross acres, gross wells, or gross reserves, as the case may be.
NYMEX	New York Mercantile Exchange.
ngl	Natural gas liquids, or liquid hydrocarbons found in association with natural gas.
Overriding royalty interest	Is similar to a basic royalty interest except that it is created out of the working interest. For example, an operator possesses a standard lease providing for a basic royalty to the lessor or mineral rights owner of 1/8 of 8/8. This then entitles the operator to retain 7/8 of the total oil and natural gas produced. The 7/8 in this case is the 100% working interest the operator owns. This operator may assign its working interest to another operator subject to a retained 1/8 overriding royalty. This would then result in a basic royalty of 1/8, an overriding royalty of 1/8 and a working interest of 3/4. Overriding royalty interest owners have no obligation or responsibility for developing and operating the property. The only expenses borne by the overriding royalty owner are a share of the production or severance taxes and sometimes costs incurred to make the oil or gas salable.

Plugging and abandonment

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

Present value of future net revenues (PV-10)

The present value of estimated future revenues to be generated from the production of proved reserves, before income taxes, calculated in accordance with Financial Accounting Standards Board guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%. PV-10 uses year-end prices for 2008 and prior years and the arithmetic 12-month average beginning-of-the-month price for 2009 and subsequent years.

Production

Natural resources, such as oil or gas, taken out of the ground.

Proved oil and gas reserves

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations — prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. For 2009 and subsequent years, the price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved developed oil and gas reserves

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

Proved undeveloped oil and gas reserves

Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Probable reserves

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Possible reserves

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project. Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves. Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the Company believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir. Where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

Productive well

A well that is found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or gas well.

Project

A targeted development area where it is probable that oil or natural gas can be produced from new wells.

Prospect

A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

R/P

The reserves to production ratio. The reserve portion of the ratio is the amount of a resource known to exist in an area and to be economically recoverable. The production portion of the ratio is the amount of resource used in one year at the current rate.

Recompletion — The process of re-entering an existing well bore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

Reserves — Oil, natural gas and gas liquids thought to be accumulated in known reservoirs.

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

Secondary recovery — A recovery process that uses mechanisms other than the natural pressure of the reservoir, such as gas injection or water flooding, to produce residual oil and natural gas remaining after the primary recovery phase.

Shut-in — A well that has been capped (having the valves locked shut) for an undetermined amount of time. This could be for additional testing, could be to wait for pipeline or processing facility, or could be for a number of other reasons.

Standardized measure — The present value of estimated future cash inflows from proved oil and natural gas reserves, less future development, abandonment, production and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized measure differs from PV-10 because standardized measure includes the effect of future income taxes.

Successful — A well is determined to be successful if it is producing oil or natural gas, or awaiting hookup, but not abandoned or plugged.

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

Water flood — A method of secondary recovery in which water is injected into the reservoir formation to displace residual oil and enhance hydrocarbon recovery.

Working interest — The operating interest that gives the owner thereof the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

Item 1. *BUSINESS*

Website Access to Reports

We make our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports, filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, available free of charge on or through our Internet website, www.magnumhunterresources.com, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

The Company

Overview

We are an independent oil and gas company engaged in the acquisition, development and production of oil and natural gas, primarily in West Virginia, North Dakota, Texas and Louisiana. We are presently active in three of the most prolific shale resource plays in the United States, namely the Marcellus Shale, Eagle Ford Shale and Williston Basin/Bakken Shale. The Company is a Delaware corporation and was incorporated in 1997. In 2005, Magnum Hunter began oil and gas operations under the name Petro Resources Corporation. In May 2009, Magnum Hunter (then known as Petro Resources Corporation) restructured its management team and refocused its business strategy, and in July 2009 changed its name to Magnum Hunter Resources Corporation. The restructured management team includes Gary C. Evans, as Chairman and Chief Executive Officer. Mr. Evans is the former founder, chairman and chief executive officer of Magnum Hunter Resources, Inc., a company of similar name that was sold to Cimarex Energy Corporation for $2.2 billion in June 2005.

The Company's new management implemented a business strategy consisting of exploiting the Company's inventory of lower risk drilling locations and the acquisition of undeveloped leases and long-lived proved reserves with significant exploitation and development opportunities primarily located in unconventional resource plays. As a result of this strategy, the Company has substantially increased its assets and production base through a combination of acquisitions and ongoing development drilling efforts, the Company's percentage of operated properties has increased significantly, its inventory of acreage and drilling locations in resource plays has grown and its management team has been expanded. Recently, management has focused on further developing and exploiting unconventional resource plays, the acquisition of additional operated properties and the development of associated midstream opportunities directly related to these regions.

At December 31, 2010, our proved reserves were 13.4 mmboe, were approximately 51% oil, had a standardized measure of $128 million and had a PV-10 value of $177.8 million on an SEC basis and $242.6 million on a NYMEX basis. Our proved reserves at year end 2010 increased 216% from the level at year end 2009. Our average daily production volumes for 2010 were 1,301 boepd, which represent a 224% increase from those volumes for 2009 (giving effect to the Company's sale in October 2010 of its Cinco Terry property as if such sale occurred at the beginning of each period). Our daily production volumes were approximately 2,732 boepd at December 31, 2010.

The principal executive offices of Magnum Hunter are located at 777 Post Oak Boulevard, Suite 650, Houston, Texas 77056, its telephone number is (832) 369-6986 and its website is www.magnumhunterresources.com.

Unless stated otherwise or unless the context otherwise requires, all references in this report to Magnum Hunter, the Company, we, our, ours and us are to Magnum Hunter Resources Corporation and its consolidated subsidiaries.

Recent Developments

During the past year, the Company expanded, and more recently announced the pending further expansion of, its position in the Marcellus Shale area of West Virginia and Bakken Shale area of North Dakota and Canada through several significant transactions (completed and pending) discussed below.

Completed Triad Acquisition. On February 12, 2010, the Company closed the acquisition of substantially all of the assets of privately-held Triad Energy Corporation and certain of its affiliates, which we refer to collectively as Triad Energy, a 23-year old Appalachian Basin focused oil and gas production company. The Company acquired the assets of Triad Energy in connection with Triad Energy's reorganization under Chapter 11 of the United States Bankruptcy Code for consideration totaling approximately $81 million. The acquired assets are located in West Virginia, Ohio and Kentucky, in the Appalachian Basin. The acquired assets included (i) conventional, mature oil fields under primary and secondary development containing approximately 5.1 mmboe of proved reserves at December 31, 2009 (65% oil); (ii) over 2,000 producing wells (99% of which are operated by the Company's subsidiary, Triad Hunter, LLC); (iii) over 88,417 net acres, including over 47,000 net acres in the Marcellus Shale; (iv) approximately 182 miles of natural gas pipeline and/or rights-of-way; (v) three drilling rigs and service equipment; and (vi) two commercial salt water disposal facilities.

Completed PostRock Acquisition. On December 24, 2010, the Company's subsidiary, Triad Hunter, LLC, which we refer to as Triad Hunter, entered into a definitive agreement to acquire certain Marcellus Shale oil and gas properties and leasehold mineral interests located in Wetzel and Lewis Counties, West Virginia from affiliates of PostRock Energy Corporation.

On December 30, 2010, Triad Hunter closed on the first phase of the transaction for the acquisition of certain Marcellus Shale assets located in Wetzel County for a total purchase price of $28 million. The purchase price consisted of (i) $14 million in cash and (ii) approximately 2.25 million newly issued restricted common shares of Magnum Hunter. On January 14, 2011, Triad Hunter closed on the second phase of the transaction for the acquisition of certain Marcellus Shale assets located in Lewis County for a total purchase price of $11.75 million. The purchase price consisted of (i) $5.875 million in cash and (ii) 946,314 newly issued restricted common shares of Magnum Hunter.

The third phase of the transaction is contemplated to close in the future for Magnum Hunter to acquire the third and smallest package of assets, subject to the determination by Magnum Hunter that certain events and conditions precedent to the closing have occurred or been satisfied.

Triad Hunter operates 100% of the properties acquired in the first two phases of the transaction. These properties include a total of approximately 9,423 gross acres (6,758 net acres), comprised of approximately 4,451 gross acres (2,225 net acres) in Wetzel County and approximately 4,972 gross acres (4,533 net acres) in Lewis County. The acquired acreage is located in the general proximity of Triad Hunter's existing Marcellus Shale acreage located in Tyler, Pleasants and Doddridge Counties, West Virginia. The majority of future lease expirations across the acquired acreage can be extended through a manageable drilling program which is planned for early 2011. The Company's proved reserves at December 31, 2010 included approximately 11.64 bcfe associated with the properties acquired in the first phase of the transaction.

Pending NGAS Resources Acquisition. On December 23, 2010, the Company entered into an arrangement agreement with NGAS Resources, Inc., a British Columbia corporation, which we refer to as NGAS, pursuant to which the Company will acquire all of the issued and outstanding equity of NGAS. NGAS is an independent exploration and production company focused on unconventional natural gas plays in the eastern United States, principally in the southern Appalachian Basin (the Huron and Weir Shales in Kentucky).

The proposed acquisition will be implemented pursuant to a court-approved plan of arrangement under British Columbia law. Under the plan of arrangement, each common share of NGAS will be transferred to the Company for the right to receive 0.0846 shares of the Company's common stock. Upon closing of the transaction, Magnum Hunter will issue approximately 6.6 million common shares to the NGAS shareholders, representing (i) approximately 5% of Magnum Hunter's fully diluted common shares outstanding as of February 14, 2011 (such percentage assuming completion of both the NGAS acquisition and the pending NuLoch Resources Inc. acquisition described below) or (ii) approximately 7% of Magnum Hunter's fully diluted common shares outstanding as of February 14, 2011 (such percentage assuming completion of the NGAS acquisition but not the pending NuLoch Resources Inc. acquisition). Certain NGAS liabilities will be refinanced under a new senior credit facility to be provided to the Company by BMO Capital Markets. In connection with the pending NuLoch Resources Inc. acquisition, the Company received a commitment for the new senior credit facility, which will have an initial borrowing base of $145 million, assuming completion of both acquisitions.

The NGAS assets to be acquired by the Company include proved reserves of 78.4 bcfe as of December 31, 2009 (74% natural gas and 65% proved developed producing), long-lived reserves with an R/P ratio of 23.4 years, daily production of approximately 9.2 mmcfe as of September 30, 2010 and approximately 330,000 gross lease acres (68% undeveloped) in Kentucky. (As of February 15, 2011, information with respect to NGAS's proved reserves as of December 31, 2010 was not yet available.)

The NGAS acquisition requires approval of NGAS's shareholders, and is subject to customary closing conditions. The NGAS acquisition is scheduled to close on or about March 31, 2011, although there is no assurance that the acquisition will ultimately be consummated.

NGAS transaction highlights:

- Multi-year inventory of approximately 2,400 identified low-risk horizontal unconventional drilling locations (historical success ratio of 98%)
- Ability to achieve an estimated $7 to $8 million of synergies and cost reductions through a restructured gas gathering and transportation agreement; consolidation of general and administrative expenses with Triad Hunter and Magnum Hunter's corporate headquarters; elimination of duplicative public company expenses; and the potential spin-off of NGAS's broker-dealer business unit to a third party management group
- Exposure to highly attractive Huron Shale leases
- Substantial liquids potential in emerging Weir oil play with existing lease inventory
- Highly accretive to reserves, production and cash flow per share
- Ability to hold significant lease acreage without substantial drilling expenditures required in the immediate future

Pending NuLoch Resources Acquisition. On January 19, 2011, the Company entered into an arrangement agreement among the Company, MHR ExchangeCo Corporation, a newly-formed corporation existing under the laws of the Province of Alberta and an indirect wholly owned subsidiary of the Company, which we refer to as ExchangeCo, and NuLoch Resources Inc., a corporation existing under the laws of the Province of Alberta, which we refer to as NuLoch, pursuant to which the Company through ExchangeCo will acquire all of the issued and outstanding equity of NuLoch. NuLoch is a Canadian public oil and natural gas producer with headquarters in Calgary, Alberta.

The proposed acquisition will be implemented pursuant to a court-approved plan of arrangement under Alberta law. The arrangement will involve an exchange of NuLoch's common shares to the Company for shares of the Company's common stock and/or exchangeable shares of ExchangeCo, as described below. Pursuant to the plan of arrangement, holders of NuLoch shares who are residents of Canada will receive, at the holder's election, (i) a number of exchangeable shares equal to the number of NuLoch shares exchanged multiplied by the exchange ratio of 0.3304, (ii) a number of Magnum Hunter common shares equal to the number of NuLoch shares exchanged multiplied by the exchange ratio, or (iii) a combination of exchangeable shares and Magnum Hunter common shares as described in clauses (i) and (ii) above. Holders of NuLoch shares who are non-Canadian residents will receive a number of Magnum Hunter common shares equal to the number of NuLoch shares exchanged multiplied by the exchange ratio. The exchangeable shares will be exchangeable into Magnum Hunter common shares (on a share-for-share basis) and will carry voting and dividend/distribution rights which are designed to put holders of the exchangeable shares in the same functional and economic position as holders of Magnum Hunter common shares. Any exchangeable shares not previously exchanged will be automatically exchanged for Magnum Hunter common shares on the one year anniversary of the closing date of the proposed transaction, unless the Company exchanges them earlier upon the occurrence of certain events.

In connection with the proposed transaction, Magnum Hunter will issue approximately 42.8 million common shares (including Magnum Hunter common shares issuable upon exchange of the exchangeable shares of ExchangeCo) to the NuLoch securityholders, representing (i) approximately 32% of Magnum Hunter's fully diluted common shares outstanding as of February 14, 2011 (such percentage assuming completion of both the NuLoch and NGAS acquisitions) or (ii) approximately 34% of Magnum Hunter's fully diluted common shares outstanding as of February 14, 2011 (such percentage assuming completion of the NuLoch acquisition but not the NGAS acquisition). As of December 31, 2010, NuLoch had no outstanding long-term debt.

In connection with the proposed transaction, Magnum Hunter has received a commitment for a new $250 million senior credit facility with an initial borrowing base of $145 million (assuming completion of both the NuLoch and NGAS acquisitions) to be provided by BMO Capital Markets, secured by the Company's existing asset base, including the assets being acquired from NuLoch and NGAS.

The NuLoch acquisition requires approval of NuLoch's shareholders and optionholders, and the issuance of Magnum Hunter common stock in connection with the acquisition requires approval of Magnum Hunter's stockholders. The NuLoch acquisition is also subject to customary closing conditions. The NuLoch acquisition is scheduled to close no later than May 31, 2011, although there is no assurance that the acquisition will ultimately be consummated.

NuLoch is actively developing its existing property portfolio in North Dakota and Saskatchewan, predominately in the evolving Bakken-Three Forks Sanish formations of the mid-continental Williston Basin in the United States and Canada. NuLoch's assets include various interests in approximately 67 wells in the Williston Basin and six drilling rigs drilling new wells in the United States and Canada at year end 2010.

NuLoch's assets include the following key attributes (although Canadian companies customarily report proved reserves and other oil and natural gas operating information on a gross basis, the following information has been provided to the Company by NuLoch's management on a net ownership basis):

- Proved reserves (1P) of 5.2 mmboe as of December 31, 2010 (82% crude oil and 25% proved developed producing)

- Proved and probable reserves (2P) of 8.2 mmboe as of December 31, 2010

- Productive capacity as of February 14 , 2011 of approximately 1,550 boe per day (86% crude oil, 70% from the Williston Basin), of which 1,080 boe per day of productive capacity is from 14 net Bakken-Three Forks Sanish wells drilled and completed

- An additional 630 boe per day 30-day production rate (IP-30 rate) of potential production exists behind pipe in standing cased and/or wells currently drilling in the Williston Basin

- Approximately 71,600 net Williston Basin mineral lease acres (32,900 located in Divide and Burke Counties, North Dakota) which are prospective for the Bakken-Three Forks Sanish formations

- Approximately 50,680 net mineral lease acres located in Alberta with estimated net daily production of 470 boe per day (53% light crude oil)

NuLoch transaction highlights:

- Multi-year inventory of approximately 267 net identified Williston Basin drilling locations (approximately 7.3% booked as proved reserves), representing estimated risked reserve potential of 31.4 mmboe (estimated unrisked reserve potential is 80.0 mmboe)

- Long-lived reserves with an R/P ratio of 9.2 years

- All identified Williston Basin drilling locations are targeting the Bakken-Three Forks / Sanish formations using long reach horizontal drilling and multi-stage fracturing techniques

- Estimated per well IP-30 rate in the 350 boe per day range with per well EURs in the 475 mboe range and all in costs of approximately $7.0 million per well in the North Dakota acreage

- Estimated internal rates of return of approximately 35% (based on a NYMEX price of $85 per barrel of oil)

Magnum Hunter's Summary of Proved Reserves, Wells and Production

SEC Case Reserve Summary

	At December 31, 2010					
				Productive Wells		
Area	Proved Reserves(a) (mmboe)	PV-10(b)(c) (Millions)	% Oil	Gross	Net	2010 Average Daily Production Volumes(d)(e) (boe)
Appalachia	9.182	$104.26	35%	2,090	2,014.1	774
North Dakota	2.508	$ 46.55	96%	151	70.9	361
Texas	1.435	$ 20.86	64%	17	5.8	127
Other	0.274	$ 6.13	88%	4	0.4	39
Total	**13.400**	**$177.80**	**51%**	**2,262**	**2,091.2**	**1,301**

(a) Mmboe is defined as one million barrels of oil equivalent determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

(b) The prices used to calculate this measure were $79.43 per barrel of oil and $4.37 per mmbtu of natural gas. The prices represent the average prices per barrel of oil and per mmbtu of natural gas at the beginning of each month in the 12-month period prior to the end of the reporting period. These prices were adjusted to reflect applicable transportation and quality differentials on a well-by-well basis to arrive at realized sales prices used to estimate our reserves at this date.

(c) The standardized measure for our proved reserves at December 31, 2010 was $128 million. See "Item 2. Properties — Reserves" for a definition of pre-tax PV-10 and a reconciliation of our standardized measure to our pre-tax PV-10 value.

(d) Average daily production volumes calculated based on 360-day year.

(e) Excluding production from the Cinco Terry discontinued operations. See note 6 to our consolidated financial statements.

NYMEX Futures Strip Case Reserve Summary

	At December 31, 2010					
				Productive Wells		
Area	Proved Reserves(a) (mmboe)	PV-10(b) (Millions)	% Oil	Gross	Net	2010 Average Daily Production Volumes(c)(d) (boe)
Appalachia	9.636	$142.49	35%	2,090	2,014.1	792
North Dakota	2.664	$ 61.39	95%	151	70.9	361
Texas	1.988	$ 30.87	71%	17	5.8	127
Other	0.277	$ 7.82	88%	4	0.4	39
Total	**14.566**	**$242.57**	**52%**	**2,262**	**2,091.2**	**1,319**

(a) Mmboe is defined as one million barrels of oil equivalent determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

(b) The prices used to calculate this measure were the NYMEX futures strip prices as of December 31, 2010.

(c) Average daily production volumes calculated based on 360-day year.

(d) Excluding production from the Cinco Terry discontinued operations. See note 6 to our consolidated financial statements.

Business Strategy

Our business strategy is to create significant value for our stockholders by growing reserves, production volumes and cash flow through a combination of cost effective development of our properties and strategic acquisitions. Key elements of our business strategy include:

Focus on Unconventional Resource Plays — We intend to focus on the development and expansion of our properties in the Marcellus Shale, Eagle Ford Shale and Williston Basin/Bakken Shale. As of February 15, 2011, the Company had over 138,438 gross acres (88,045 net acres) and over 600 identified drilling locations in these three areas. With recent improvements in drilling and completion technologies, the development of unconventional resources can be highly economic. We believe that these areas represent the potential for the best return on invested capital for our stockholders.

Strategic Acquisitions — The Company intends to continue to opportunistically acquire additional acreage and reserves in our core areas. In the past year, we have completed acquisitions from Triad Energy and PostRock Energy Corporation and have entered into definitive agreements for pending acquisitions of NGAS Resources, Inc. and NuLoch Resources Inc., which are anticipated to be completed in the first half of 2011. We believe that our acquisition and operational track record, as well as our extensive industry relationships, will provide for continued growth opportunities in the future.

Focus on Acquisition and Development of Oil and Liquids Rich Resources — We plan to focus our development and acquisition efforts primarily on oil reserves in the Williston Basin (Bakken-Three Forks/ Sanish) and in the oil window of the Eagle Ford Shale in south Texas. In addition, we are focused on liquids rich gas development (1,250 plus btu) in the Marcellus Shale area of northwest West Virginia. We believe these areas present the potential for the most attractive returns on employed capital.

Operating Control — We believe that operatorship provides the ability to maximize the value of our assets, including control of the timing of drilling expenditures, greater control of operational costs and the ability to increase production volumes. During the past year, we have significantly increased the number of wells that we operate and control.

Employment of Advanced Technologies — We use state of the art, advanced drilling, completion and production technologies, allowing us the best opportunity for drilling and completion success. Our technical team continually reviews the most current technologies and applies them to our reserve base for the effective development of our project inventory.

Leveraging the Experience of our Management Team — Management actively utilizes its track record and relationships with industry partners, commercial and investment banks and institutional and private equity investors in an effort to rapidly build and develop the Company's asset base and finance the Company's growth on the most cost effective basis.

Development of Eureka Hunter Pipeline Assets — We are continuing the construction of a 20 inch steel pipeline to support the development of our Marcellus Shale acreage position. This pipeline will enable the Company to develop our substantial natural gas and ngl resources in the Marcellus Shale, as well as provide the opportunity for substantial cash flow from the gathering of third party volumes of natural gas and ngls. We have allocated $25 million of our 2011 capital budget to grow our midstream business unit. The Company began flowing gas through the initial phase of its pipeline in the fourth quarter of 2010. The Company has contracted to purchase a 200 mmcfpd capacity cryogenic processing plant and anticipates delivery of the plant in October 2011. The plant is expected to be operational by mid-year 2012. We continue to actively pursue joint venture and other financing structures to support the expansion of the pipeline, and anticipate ultimately increasing its throughput capacity to approximately 200 mmcfpd.

Competitive Strengths

We believe that our key competitive strengths include:

Experienced Management Team — Our senior management team, on average, has over 25 years of experience in the oil and gas industry. Senior management has extensive experience in managing, financing and operating public oil and gas companies. Magnum Hunter Resources, Inc., unrelated to the Company, founded by Gary C. Evans in 1985, achieved an average annual internal rate of return of 38% to shareholders during the 15 years it was publicly traded. Additionally, our management team has collectively completed over $30 billion in financing transactions and acquisitions in the oil and gas industry, and our personnel have extensive expertise in all key operational disciplines.

Balanced Long-Lived Asset Base with Substantial Oil Reserves — As of December 31, 2010, we owned interests in 2,262 gross (2,091 net) productive wells across approximately 348,722 gross (139,481 net) mineral acres, predominately in the Marcellus Shale, Eagle Ford Shale and Williston Basin/Bakken Shale. We believe this geographic mix of properties and drilling opportunities, combined with our continuing business strategy of acquiring and exploiting properties in these areas, present us with multiple opportunities in executing our strategy. Our R/P ratio life is approximately 13.4 years based on year-end 2010 proved reserves of 13.4 mmboe. As of December 31, 2010, approximately 51% of our proved reserves were oil and 55% of our production was oil.

Acreage Position and Drilling Inventory in Core Resource Areas — As of February 15, 2011, we had over 88,045 net acres in our core resource areas, including approximately 56,595 net acres in the Marcellus Shale, 25,000 net acres in the Eagle Ford Shale and 6,450 net acres in the Williston Basin/Bakken Shale. We have identified an inventory of over 600 drillable locations in these core areas, with less than 10% currently booked as proved reserves.

Operated Assets — The Company operates a substantial majority of its assets. As of December 31, 2010, we operated approximately 87% of our producing wells and 66% of our proved reserves.

Marcellus Infrastructure Assets — The Company controls approximately 182 miles of pipeline, gathering systems and/or rights-of-way to provide critical takeaway capacity and third party gathering in the capacity-constrained Marcellus Shale area of West Virginia. Following our planned expansion efforts, we estimate our natural gas pipeline system will have throughput capacity of approximately 200 mmcfpd. In addition, we own and operate a 120,000 barrel per month commercial salt water disposal facility in Ohio, a second commercial salt water disposal facility located in Kentucky, three drilling rigs and various service equipment, which contribute to the efficient operation and development of our assets in the Marcellus Shale area.

2011 Operating Capital Budget

We estimate our capital budget for fiscal year 2011 to be approximately $150 million (excluding any budgeted amounts for operations that may be acquired pursuant to the pending NGAS and NuLoch acquisitions), including:

- Approximately $65 million to drill 14 gross (7 net) horizontal wells in Texas targeting the Eagle Ford Shale;
- Approximately $60 million to drill 15 gross (12.5 net) horizontal wells in the Appalachian Basin targeting the Marcellus Shale; and
- An estimated $25 million for the further development of the Eureka Hunter midstream system in northwest West Virginia.

Because of the volatility of commodity prices and the risks involved in our industry, we believe in remaining flexible in our capital budgeting process. When appropriate, we may defer existing capital projects to pursue an attractive acquisition opportunity or reallocate capital to projects we believe can generate higher rates of return on employed capital. We also believe in maintaining a strong balance sheet and using commodity price hedging. This allows us to be more opportunistic in a lower commodity price environment as well as providing more consistent financial results in the long-term.

Marketing and Pricing

We derive revenue principally from the sale of oil and natural gas. As a result, our revenues are determined, to a large degree, by prevailing prices for crude oil and natural gas. We sell our oil and natural gas on the open market at prevailing market prices. The market price for oil and natural gas is dictated by supply and demand, and we cannot accurately predict or control the price we may receive for our oil and natural gas.

We use commodity price hedging instruments to reduce our exposure to oil and natural gas price fluctuations and to help ensure that we have adequate cash flow to fund our debt service costs, preferred dividend payments and future capital programs. From time to time, we may enter into futures contracts, collars and basis swap agreements, as well as fixed price physical delivery contracts; however, it is our preference to utilize hedging strategies that provide downside commodity price protection without unduly limiting our revenue potential in an environment of rising commodity prices. We use hedging primarily to manage price risks and returns on certain acquisitions and drilling programs. Our policy is to consider hedging an appropriate portion of our production at commodity prices we deem attractive.

Our revenues, cash flows, profitability and future rate of growth depend substantially upon prevailing prices for oil and natural gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. Lower prices may also adversely affect the value of our reserves and make it uneconomic for us to commence or continue drilling for crude oil and natural gas. Historically, the prices received for oil and natural gas have fluctuated widely. Among the factors that can cause these fluctuations are:

- uncertainty in the global economy;
- changes in global supply and demand for oil and natural gas;
- the condition of the U.S. and global economies;
- the actions of certain foreign countries;
- the price and quantity of imports of foreign oil and liquid natural gas;
- political conditions, including embargoes, war or civil unrest in or affecting oil producing activities of certain countries;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- production or pricing decisions made by the Organization of Petroleum Exporting Countries (OPEC);
- weather conditions;
- technological advances affecting energy consumption or production; and
- the price and availability of alternative fuels.

From time to time, we enter into hedging arrangements to reduce our exposure to decreases in the prices of oil and natural gas. Hedging arrangements may expose us to risk of significant financial loss in certain situations, including circumstances where:

- our production and/or sales of oil and natural gas are less than expected;
- payments owed under derivative hedging contracts come due prior to receipt of the hedged month's production revenue; or
- the counterparty to the hedging contract defaults on its contract obligations.

In addition, hedging arrangements limit the benefit we would receive from increases in the price of oil and natural gas. Hedging transactions we may enter into may not adequately protect us from a decline in the price of oil and natural gas above certain caps. Furthermore, should we choose not to engage in hedging transactions in the future (to the extent we are not otherwise obligated to hedge under our senior credit facility), we may be adversely affected by volatility in oil and natural gas prices.

As of December 31, 2010, we had the following hedges in place:

	2011	2012
Natural Gas Hedges		
Swaps		
Volume (mmbtu/d)	112	99
Price per mcf	$ 5.98	$ 6.15
Collars		
Volume (mmbtu/d)	2,113	1,884
Floor Price per mcf	$ 5.37	$ 5.00
Ceiling Price per mcf	$ 7.43	$ 8.65
Total Gas Volume Hedged	811,980	723,600
Total proved developed producing(PDP)	1,598,220	1,143,700
Total % of PDP Hedged	51%	63%

	2011	2012
Crude Oil Hedges		
Floors		
Volume (bbls/d)	158	151
Price per bbl	$ 80.00	$ 80.00
Swaps		
Volume (bbls/d)	42	N/A
Price per bbl	$ 85.08	N/A
Collars		
Volume (bbls/d)	496	187
Floor Price per bbl	$ 73.49	$ 78.66
Ceiling Price per bbl	$ 95.95	$ 102.14
Total Oil Volume Hedged	254,070	123,592
Total PDP	360,010	290,710
Total % of PDP Hedged	71%	43%

Competition

The oil and natural gas industry is highly competitive in all phases. We encounter competition from other oil and natural gas companies in all areas of operation, including the acquisition of leases and properties. Our competitors include numerous independent oil and natural gas companies and individuals. Many of our competitors are large, well established companies that have substantially larger operating staffs and greater capital resources than we do.

The prices of our products are controlled by the world oil market; thus, competitive pricing behavior in this regard is considered unlikely; however, competition in the oil and natural gas exploration industry exists in the form of competition to acquire the most promising properties and obtain the most favorable prices for the costs of drilling and completing wells. Competition for the acquisition of oil and gas properties is intense with many properties available in a competitive bidding process in which we may lack technological information or expertise available to other bidders. Therefore, we may not be successful in acquiring and developing profitable properties in the face of this competition. Our ability to acquire additional properties in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in an efficient manner even in a highly competitive environment. See "Item 1A. Risk Factors — Competition in the oil and natural gas industry is intense, which may adversely affect our ability to compete."

Operating Hazards and Risks

Drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be encountered. There can be no assurance that the new wells we drill will be productive or that we will recover all or any portion of our investment. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells, but also from wells that are productive, but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. The cost and timing of drilling, completing and operating wells is often uncertain. Our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, many of which are beyond our control, including low oil and natural gas prices, title problems, weather conditions, delays by or disputes with project participants, compliance with governmental requirements, shortages or delays in the delivery of equipment and services and increases in the cost for such equipment and services. Our future drilling activities may not be successful and, if unsuccessful, such failure may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our operations are subject to hazards and risks inherent in drilling for and producing and transporting oil and natural gas, such as fires, natural disasters, explosions, encountering formations with abnormal pressures, blowouts, craterings, pipeline ruptures and spills, any of which can result in the loss of hydrocarbons, environmental pollution, personal injury claims and other damage to our properties and those of others. We maintain insurance against some but not all of the risks described above. In particular, the insurance we maintain does not cover claims relating to failure of title to oil and natural gas leases, loss of surface equipment at well locations, business interruption, loss of revenue due to low commodity prices or loss of revenue due to well failure. Furthermore, in certain circumstances where such insurance is available, we may determine not to purchase it due to cost or other factors. The occurrence of an event that is not covered by, or not fully covered by, insurance could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Governmental Regulation

Our oil and natural gas exploration and production activities, and our midstream activities, are subject to extensive laws, rules and regulations promulgated by federal and state legislatures and agencies. Failure to comply with such laws, rules and regulations can result in substantial penalties, including the delay or stopping of our operations. The legislative and regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our profitability.

Our exploration and drilling activities, including the operation and construction of pipelines, plants and other facilities for gathering, processing or storing oil, natural gas and other products, are subject to stringent federal, state and local laws and regulations governing environmental quality, including those relating to oil spills and pollution control, that are constantly changing. Although such laws and regulations can increase the cost of planning, designing, installing and operating such facilities, it is anticipated that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations governing the release of materials in the environment or otherwise relating to the protection of the environment, will not have a material effect upon our business operations, capital expenditures, operating results or competitive position. See "Item 1A. Risk Factors — Our operations expose us to substantial costs and liabilities with respect to environmental matters."

Climate change has become the subject of an important public policy debate. Climate change remains a complex issue, with some scientific research suggesting that an increase in greenhouse gas emissions (GHGs) may pose a risk to society and the environment. The oil and natural gas exploration and production industry is a source of certain GHGs, namely carbon dioxide and methane. The commercial risk associated with the production of fossil fuels lies in the uncertainty of government-imposed climate change legislation, including cap and trade schemes, and regulations that may affect us, our suppliers and our customers. The cost of meeting these requirements may have an adverse impact on our business, financial condition, results of operations and cash flows, and could reduce the demand for our products. See "Item 1A. Risk Factors — Climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil, natural gas and NGLs that we produce."

Formation

We were incorporated in the State of Delaware on June 4, 1997.

Employees

At December 31, 2010, we had 165 full-time employees, of which 14 were officers. None of our employees is represented by a union. Management considers our relations with employees to be very good.

Facilities

As of December 31, 2010, our principal executive offices are located in Houston, Texas, and consist of approximately 16,944 square feet of leased office space. Our lease expires with respect to approximately 9,000, 6,000 and 1,600 square feet of this space in January 2016, May 2012 and December 2013, respectively. We also inherited, through the acquisition of our subsidiary, Sharon Hunter Resources, Inc., approximately 6,031 square feet of office space located in Houston, Texas under a lease that expires in February 2012. We have sub-leased this space. Our Triad Hunter offices consist of approximately 7,608 square feet of leased office space in Marietta, Ohio, as well as field offices in Kentucky and West Virginia.

Available Information

Our executive offices are located at 777 Post Oak Blvd., Suite 650, Houston, Texas 77056. Our telephone number is (832) 369-6986. We file annual, quarterly and current reports, proxy statements and other documents with the SEC under the Exchange Act. The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a website that contains reports, proxy and information statements, and other information that is electronically filed with the SEC. The public can obtain any documents that we file with the SEC at www.sec.gov. We also make available free of charge on our website (www.magnumhunterresources.com) our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we file such material with, or furnish it to, the SEC.

Item 1A. *RISK FACTORS*

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

Risks Related to Our Business

Future economic conditions in the U.S. and global markets may have a material adverse impact on our business and financial condition that we currently cannot predict.

The U.S. and other world economies are slowly recovering from a recession which began in 2008 and has extended into 2011. While economic growth has resumed, it remains modest and the timing of an economic recovery is uncertain. There are likely to be significant long-term effects resulting from the recession and credit market crisis, including a future global economic growth rate that is slower than what was experienced in recent years. Unemployment rates remain very high and business and consumer confidence levels have not yet fully recovered to pre-recession levels. In addition, more volatility may occur before a sustainable, yet lower, growth rate is achieved. Global economic growth drives demand for energy from all sources, including for oil and natural gas. A lower future economic growth rate will result in decreased demand for our crude oil and natural gas production as well as lower commodity prices, which will reduce our cash flows from operations and our profitability.

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

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

- uncertainty in the global economy;
- changes in global supply and demand for oil and natural gas;
- the condition of the U.S. and global economies;
- the actions of certain foreign countries;
- the price and quantity of imports of foreign oil and liquid natural gas (LNG);
- political conditions, including embargoes, war or civil unrest in or affecting oil producing activities of certain countries;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- production or pricing decisions made by OPEC;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis, but also may reduce the amount of oil and natural gas that we can produce economically. The higher operating costs associated with many of our oil fields will make our profitability more sensitive to oil price declines. A sustained decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

The recent financial crisis may have lasting effects on our liquidity, business and financial condition that we cannot predict.

Liquidity is essential to our business. Our liquidity could be substantially negatively affected by an inability to obtain capital in the long-term or short-term debt or equity capital markets or an inability to access bank financing. A prolonged credit crisis and related turmoil in the global financial system would likely materially affect our liquidity, business and financial condition. The economic situation could also adversely affect the collectibility of our trade receivables or performance by our suppliers and cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection.

If our access to oil and gas markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases. Our ability to sell natural gas and/or receive market prices for our natural gas may be adversely affected by pipeline and gathering system capacity constraints.

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

If drilling in the Marcellus Shale, Eagle Ford Shale and Bakken Shale areas proves to be successful, the amount of oil and natural gas being produced by us and others could exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available in these areas. If this occurs, it will be necessary for new pipelines and gathering systems to be built. Because of the current economic climate, certain pipeline projects that are planned for the Marcellus Shale, Eagle Ford Shale and Bakken Shale areas may not occur for lack of financing. In addition, capital constraints could limit our ability to build intrastate gathering systems necessary to transport our gas to interstate pipelines. In such event, we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell natural gas production at significantly lower prices than those quoted on NYMEX or than we currently project for these specific regions, which would adversely affect our results of operations.

A portion of our natural gas and oil production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow.

We depend on a relatively small number of purchasers for a substantial portion of our revenue. The inability of one or more of our purchasers to meet their obligations may adversely affect our financial results.

We derive a significant amount of our revenue from a relatively small number of purchasers. Our inability to continue to provide services to key customers, if not offset by additional sales to our other customers, could adversely affect our financial condition and results of operations. These companies may not provide the same level of our revenue in the future for a variety of reasons, including their lack of funding, a strategic shift on their part in moving to different geographic areas in which we do not operate or our failure to meet their performance criteria. The loss of all or a significant part of this revenue would adversely affect our financial condition and results of operations.

Shortages of oil field equipment, services and qualified personnel could reduce our cash flow and adversely affect results of operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices and activity levels in new regions, causing periodic shortages. During periods of high oil and gas prices, we have experienced shortages of equipment, including drilling rigs and completion equipment, as demand for rigs and equipment has increased along with higher commodity prices and increased activity levels. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, oilfield equipment and services and personnel in our exploration and production operations. These types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results and/or restrict or delay our ability to drill those wells and conduct those operations that we currently have planned and budgeted, causing us to miss our forecasts and projections.

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

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

- the nature and timing of the operator's drilling and other activities;
- the timing and amount of required capital expenditures;
- the operator's geological and engineering expertise and financial resources;
- the approval of other participants in drilling wells; and
- the operator's selection of suitable technology.

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

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

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

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

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

We maintain insurance coverage against some, but not all, potential losses to protect against the risks we foresee. We do not carry business interruption insurance. We may elect not to carry certain types or amounts of insurance if our management believes that the cost of available insurance is excessive relative to the risks presented. In addition, it is not possible to insure fully against pollution and environmental risks.

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

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

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

We have limited management and staff and will be dependent upon partnering arrangements.

We have a total of approximately 168 employees as of February 14, 2011. Despite this number of employees, we expect that we will continue to require the services of independent consultants and contractors to perform various professional services, including reservoir engineering, land, legal, environmental and tax services. We will also pursue alliances with partners in the areas of geological and geophysical services and prospect generation, evaluation and prospect leasing. Our dependence on third party consultants and service providers creates a number of risks, including but not limited to:

- the possibility that such third parties may not be available to us as and when needed; and
- the risk that we may not be able to properly control the timing and quality of work conducted with respect to our projects.

If we experience significant delays in obtaining the services of such third parties or poor performance by such parties, our results of operations could be materially adversely affected.

Our business may suffer if we lose key personnel.

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

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

Our future success will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our costs of drilling, completing and operating wells are often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures could be materially and adversely affected by any factor that may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;

- unusual or unexpected geological formations;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment malfunctions, failures or accidents;
- unexpected operational events and drilling conditions;
- pipe or cement failures;
- casing collapses;
- lost or damaged oilfield drilling and service tools;
- loss of drilling fluid circulation;
- uncontrollable flows of oil, natural gas and fluids;
- fires and natural disasters;
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- oil and natural gas property title problems; and
- market limitations for oil and natural gas.

If any of these factors were to occur with respect to a particular field, we could lose all or a part of our investment in the field, or we could fail to realize the expected benefits from the field, either of which could materially and adversely affect our revenue and profitability.

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

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

We have limited experience in drilling wells to the Marcellus Shale, Eagle Ford Shale and Bakken Shale and limited information regarding reserves and decline rates in the Marcellus Shale, Eagle Ford Shale and Bakken Shale. Wells drilled to these shale areas are more expensive and more susceptible to mechanical problems in drilling and completion techniques than wells in other conventional areas.

We have limited experience in the drilling and completion of Marcellus Shale, Eagle Ford Shale and Bakken Shale wells, including limited horizontal drilling and completion experience. Other operators in the Marcellus Shale, Eagle Ford Shale and Bakken Shale plays may have significantly more experience in the drilling and completion of these wells, including the drilling and completion of horizontal wells. In addition, we have limited information with respect to the ultimate recoverable reserves and production decline rates in these areas. The wells drilled in Marcellus Shale, Eagle Ford Shale and Bakken Shale are primarily horizontal and require more stimulation, which makes them more expensive to drill and complete. The wells will also be more susceptible to mechanical problems associated with the drilling and completion of the wells, such as casing collapse and lost equipment in the wellbore due to the length of the lateral portions of these unconventional wells. The fracturing of these shale formations will be more extensive and complicated than fracturing geological formations in conventional areas of operation.

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

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

New technologies may cause our current exploration and drilling methods to become obsolete.

The oil and gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.

Our indebtedness could adversely affect our financial condition and our ability to operate our business.

As of February 17, 2011, our outstanding indebtedness was approximately $34 million. We will incur additional debt from time to time, and such borrowings may be substantial. Our debt could have material adverse consequences to us, including the following:

- it may be difficult for us to satisfy our obligations, including debt service requirements under our credit agreements;
- our ability to obtain additional financing for working capital, capital expenditures, debt service requirements and other general corporate purposes may be impaired;
- a significant portion of our cash flow is committed to payments on our debt, which will reduce the funds available to us for other purposes, such as future capital expenditures;
- we are more vulnerable to price fluctuations and to economic downturns and adverse industry conditions and our flexibility to plan for, or react to, changes in our business or industry is more limited; and
- our ability to capitalize on business opportunities, and to react to competitive pressures, as compared to others in our industry, may be limited.

We have a history of losses and cannot assure you that we will be profitable in the foreseeable future.

Since we entered the oil and gas business in April 2005, through December 31, 2010, we have incurred a cumulative net loss from operations of $41.1 million. We also recorded net losses in the first three quarters of 2010 and in the year ended December 31, 2010. If we fail to generate profits from our operations, we will not be able to sustain our business. We may never report profitable operations or generate sufficient revenue to maintain our company as a going concern.

We do not have a significant operating history and, as a result, there is a limited amount of information about us on which to make an investment decision.

We have acquired a number of properties since June 2009, and consequently, a large amount of our focus has been on assimilating the properties, operations and personnel we have acquired into our organization. Accordingly, there is little operating history upon which to judge our business strategy, our management team or our current operations.

Our proved reserves and related PV-10 as of December 31, 2010 have been reported under new SEC rules that went into effect on January 1, 2010. The estimates provided in accordance with the new SEC rules may change materially as a result of interpretive guidance that may be subsequently released by the SEC.

We have included in this report certain estimates of our proved reserves and related PV-10 at December 31, 2010 as prepared consistent with our independent reserve engineer's interpretations of the new SEC rules relating to disclosures of estimated oil and natural gas reserves. These new rules are effective for fiscal years ending on or after December 31, 2009. These new rules require SEC reporting companies to prepare their reserve estimates using revised reserve definitions and revised pricing based on 12-month unweighted first-day-of-the-month average pricing. The SEC has not specifically reviewed our reserve estimates under the new rules and has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules. Accordingly, while the estimates of our proved reserves and related PV-10 at December 31, 2010 included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the new SEC rules, those estimates could ultimately differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

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

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

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

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

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;
- the amount and timing of actual production;
- supply of and demand for oil and natural gas; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

We may be limited in our ability to book additional proved undeveloped reserves under the new SEC rules.

Another impact of the new SEC reserve rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This new rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program on our undeveloped properties.

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

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

Product price derivative contracts may expose us to potential financial loss.

To reduce our exposure to fluctuations in the prices of oil and natural gas, we currently and will likely in the future enter into derivative contracts in order to economically hedge a portion of our oil and natural gas production. Derivative contracts expose us to risk of financial loss in some circumstances, including when:

- production is less than expected;
- the counterparty to the derivative contract defaults on its contract obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

In addition, these derivative contracts may limit the benefit we would receive from increases in the prices for oil and natural gas. Under the terms of our senior credit facility, the percentage of our total production volumes with respect to which we will be allowed to enter into derivative contracts is limited, and we therefore retain the risk of a price decrease for our remaining production volume. Information as to these activities is set forth under "Management's Discussion and Analysis of Financial Condition and Results of Operations — Market Risk Management," and in Note 4, "Financial Instruments and Derivatives," to the consolidated financial statements.

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

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

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

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

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

Restrictive covenants in our senior credit facility may restrict our ability to pursue our business strategies.

Our senior credit facility with our lenders contains certain negative covenants that, among other things, restrict our ability to, with certain exceptions:

- incur indebtedness;
- grant liens;
- make certain payments;
- change the nature of our business;
- dispose of all or substantially all of our assets or enter into mergers, consolidations or similar transactions;
- make investments, loans or advances;
- pay cash dividends, unless certain conditions are met and are subject to a "basket" of $10.25 million per year available for payment of dividends on preferred stock; and
- enter into transactions with affiliates.

Our senior credit facility also requires us to satisfy certain affirmative financial covenants, including maintaining:

- an EBITDAX to interest ratio of not less than 2.5 to 1.0;
- a debt to EBITDAX ratio of not more than 4.0 to 1.0 for each fiscal quarter ending during the remaining term of the senior credit facility; and
- a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0.

We are also required to enter into certain commodity price hedging agreements pursuant to the terms of the credit facility.

Our ability to comply with these covenants may be affected by events beyond our control, and any material deviations from our forecasts could require us to seek waivers or amendments of covenants or alternative sources of financing or reduce our expenditures. We cannot assure you that such waivers, amendments or alternative financings could be obtained or, if obtained, would be on terms acceptable to us.

Our obligations under our senior credit facility are secured by substantially all of our assets, and any failure to meet our debt obligations would adversely affect our business and financial condition.

Certain of our subsidiaries, including PRC Williston LLC, Sharon Hunter Resources, Inc., Triad Hunter, LLC and Eureka Hunter Pipeline, LLC, have each guaranteed the performance of our obligations under our senior credit facility, and we have collateralized our obligations under the senior credit facility through our grant of a first priority security interest in our ownership interests in these subsidiaries and substantially all of our oil and gas properties, subject only to certain permitted liens.

Our ability to meet our debt obligations under the senior credit facility will depend on the future performance of our properties, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. Our failure to service this debt could result in a default under the credit facility, which could result in the loss of our ownership interests in the guarantor subsidiaries and our oil and gas assets and otherwise materially adversely affect our business, financial condition and results of operations.

We are subject to complex federal, state and local laws and regulations, including environmental laws, which could adversely affect our business.

Exploration for and development, exploitation, production and sale of oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax laws and environmental laws and regulations. Existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws, regulations or incremental taxes and fees, could harm our business, results of operations and financial condition. We may be required to make large expenditures to comply with environmental and other governmental regulations.

It is possible that new taxes (including those referenced under the heading "Certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated as a result of future legislation") on our industry could be implemented and/or tax benefits could be eliminated or reduced, reducing our profitability and available cash flow. In addition to the short-term negative impact on our financial results, such additional burdens, if enacted, would reduce our funds available for reinvestment and thus ultimately reduce our growth and future oil and natural gas production.

Matters subject to regulation include oil and gas production and saltwater disposal operations and our processing, handling and disposal of hazardous materials, such as hydrocarbons and naturally occurring radioactive materials, discharge permits for drilling operations, spacing of wells, environmental protection and taxation. We could incur significant costs as a result of violations of or liabilities under environmental or other laws, including third party claims for personal injuries and property damage, reclamation costs, remediation and clean-up costs resulting from oil spills and discharges of hazardous materials, fines and sanctions, and other environmental damages.

Enactment of legislative or regulatory proposals under consideration could negatively affect our business.

Numerous legislative and regulatory proposals affecting the oil and gas industry have been proposed or are under consideration by the current federal administration, Congress and various federal agencies. Among these proposals are: (1) climate change legislation introduced in Congress, Environmental Protection Agency regulations, carbon emission "cap-and-trade" regimens, and related proposals, none of which has been adopted in final form; (2) proposals contained in the President's 2012 budget to repeal various tax deductions available to oil and gas producers, such as the current tax deduction for intangible drilling and development costs, which if eliminated could raise the cost of energy production, reduce energy investment and affect the economics of oil and gas exploration and production activities; and (3) legislation being considered by Congress that would subject the process of hydraulic fracturing to federal regulation under the Safe Drinking Water Act. Generally, any such future laws and regulations could result in increased costs or additional operating restrictions, and could have an effect on future demand for oil and gas or on oil and gas prices. Until any such legislation or regulations are enacted or adopted, it is not possible to gauge their impact on our future operations or our results of operations and financial condition.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Congress is currently considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing is an important and necessary process in the completion of unconventional oil and natural gas wells in shale formations. This process involves the injection of water, sand and chemicals under pressure into rock formations to stimulate production. Sponsors of two companion bills, which are currently pending in the House Energy and Commerce Committee and the Senate Committee on Environment and Public Works Committee have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, this legislation, if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens. Several states are also considering implementing, or in some instances, have implemented, new regulations pertaining to hydraulic fracturing, including the disclosure of chemicals used in connection therewith. The adoption of any future federal or state laws or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process would make it more difficult and more expensive to complete new wells in shale formations and increase our costs of compliance and doing business.

Climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil, natural gas and NGLs that we produce.

A variety of regulatory developments, proposals or requirements and legislative initiatives have been introduced in the United States that are focused on restricting the emission of carbon dioxide, methane and other greenhouse gases. On June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, or ACESA, which would establish an economy-wide cap-and-trade program to reduce emissions of greenhouse gases in the United States, including carbon dioxide and methane. The U.S. Senate has begun work on its own legislation for controlling and reducing greenhouse gas emissions in the United States. Although it is not possible at this time to predict whether or when the Senate may act on climate change legislation, how any bill passed by the Senate would be reconciled with ACESA, or how federal legislation may be reconciled with state and regional requirements, any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the oil, natural gas and NGLs that we produce.

In 2007, the U.S. Supreme Court held in *Massachusetts, et al. v. EPA* that greenhouse gas emissions may be regulated as an "air pollutant" under the federal Clean Air Act. On December 15, 2009, the U.S. Environmental Protection Agency, or EPA, officially published its findings that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Since December 2009, the EPA has issued regulations that, among other things, require a reduction in emissions of greenhouse gases from motor vehicles and that impose greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010.

Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Any additional costs or operating restrictions associated with legislation or regulations regarding greenhouse gas emissions could have a material adverse effect on our business, financial condition and results of operation. In addition, these developments could curtail the demand for fossil fuels such as oil and gas in areas of the world where our customers operate and thus adversely affect demand for our products and services, which may in turn adversely affect our future results of operations.

We must obtain governmental permits and approvals for our drilling operations, which can be a costly and time consuming process, which may result in delays and restrictions on our operations.

Regulatory authorities exercise considerable discretion in the timing and scope of specific permit issuance. Requirements imposed by these authorities may be costly and time consuming and may result in delays in the commencement or continuation of our exploration or production operations. For example, we are often required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that proposed exploration for or production of oil or natural gas, pipeline construction, gas processing facilities and associated well production equipment may have on the environment. Further, the public may comment on and otherwise engage in the permitting process, including through intervention in the courts. Accordingly, the permits we need may not be issued, or if issued, may not be issued in a timely fashion, or may involve requirements that restrict our ability to conduct our operations or to do so profitably.

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

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

The adoption of derivatives legislation by Congress and related regulations could have an adverse impact on our ability to hedge risks associated with our business.

On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Act. The Act provides for new statutory and regulatory requirements for derivative transactions, including certain oil and gas hedging transactions. In particular, the Act includes a requirement that certain hedging transactions be cleared on exchanges and a requirement to post cash collateral for such transactions, although it is unclear whether the Act will apply to contracts for the sale of oil and gas for future delivery. The Act also provides for a potential exception from these clearing and cash collateral requirements for commercial end-users. However, many of the key concepts and defined terms under the Act must be delineated by rules and regulations to be adopted by the Commodities Futures Trading Commission, or the CFTC, and other applicable regulatory agencies. As a consequence, it is difficult to predict the effect the Act may have on our hedging activities. Depending on the rules and definitions adopted by the CFTC, we might be required to provide cash collateral for our commodities hedging transactions. Such a requirement could result in significant liquidity issues by reducing our ability to use cash for investment or other corporate purposes. Moreover, our senior credit facility, which requires us to enter into swap agreements covering at least 60% of our anticipated production from proved developed producing reserves, expressly prohibits our ability to provide cash collateral in connection with such agreements. In addition, a requirement to post cash collateral for hedging transactions could limit our ability to execute strategic hedges, which would result in increased commodity price uncertainty and volatility in our future cash flows.

Certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated as a result of future legislation.

Among the changes contained in President Obama's 2012 budget proposal released by the White House on February 14, 2011, is the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. Such changes include, but are not limited to:

- the repeal of the percentage depletion allowance for oil and gas properties;
- the elimination of current deductions for intangible drilling and development costs;
- the elimination of the deduction for certain U.S. production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The Close Big Oil Tax Loophole Act, which was introduced in the Senate in February 2011, includes many of the same proposals but is limited to taxpayers with annual gross revenues in excess of $100 million. It is unclear whether any of the foregoing changes will actually be enacted or how soon any such changes could become effective. The passage of any legislation as a result of the budget proposal, the Senate bill, or any other similar change in U.S. federal income tax law could eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Acquired properties may not be worth what we pay due to uncertainties in evaluating recoverable reserves and other expected benefits, as well as potential liabilities.

Successful property acquisitions require an assessment of a number of factors beyond our control. These factors include exploration and development potential, future oil and natural gas prices, operating costs, and potential environmental and other liabilities. These assessments are complex and inherently imprecise. Our review of the properties we acquire may not reveal all existing or potential problems. In addition, our review may not allow us to fully assess the potential deficiencies of the properties. We do not typically inspect every well, and even when we inspect a well we may not discover structural, subsurface, or environmental problems that may exist or arise. We may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities, and our contractual indemnification may not be effective. Often, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties by the previous owners. If an acquired property is not performing as originally estimated, we may have an impairment which could have a material adverse effect on our financial position and future results of operations.

Our recent acquisitions and any future acquisitions may not be successful, may substantially increase our indebtedness and contingent liabilities, and may create integration difficulties.

As part of our business strategy, we have acquired and intend to continue to acquire businesses or assets we believe complement our existing operations and business plan. We may not be able to successfully integrate these acquisitions into our existing operations or achieve the desired profitability from such acquisitions. These acquisitions may require substantial capital expenditures and the incurrence of additional indebtedness which may change significantly our capitalization and results of operations. Further, these acquisitions could result in:

- post-closing discovery of material undisclosed liabilities of the acquired business or assets;
- the unexpected loss of key employees or customers from the acquired businesses;
- difficulties resulting from our integration of the operations, systems and management of the acquired business; and
- an unexpected diversion of our management's attention from other operations.

If acquisitions are unsuccessful or result in unanticipated events or if we are unable to successfully integrate acquisitions into our existing operations, such acquisitions could adversely affect our results of operations and cash flow. The process of integrating our operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our existing business. If management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

We pursue acquisitions as part of our growth strategy and there are risks in connection with acquisitions.

Our growth has been attributable in part to acquisitions of producing properties and companies. We expect to continue to evaluate and, where appropriate, pursue acquisition opportunities on terms we consider favorable. However, we cannot assure you that suitable acquisition candidates will be identified in the future, or that we will be able to finance such acquisitions on favorable terms. In addition, we compete against other companies for acquisitions, and we cannot assure you that we will successfully acquire any material property interests. Further, we cannot assure you that future acquisitions by us will be integrated successfully into our operations or will increase our profits.

The successful acquisition of producing properties requires an assessment of numerous factors beyond our control, including, without limitation:

- recoverable reserves;
- exploration and development potential;
- future oil and natural gas prices;
- operating costs; and
- potential environmental and other liabilities.

In connection with such an assessment, we perform a review of the subject properties that we believe to be generally consistent with industry practices. The resulting assessments are inexact and their accuracy uncertain, and such a review may not reveal all existing or potential problems, nor will it necessarily permit us to become sufficiently familiar with the properties to fully assess their merits and deficiencies within the time frame required to complete the transactions. Inspections may not always be performed on every well, and structural and environmental problems are not necessarily observable even when an inspection is made.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may be substantially different in operating and geologic characteristics or geographic location than our existing properties. While our current operations are focused in the south Texas, Ohio/West Virginia and North Dakota regions, we are pursuing and expect to continue to pursue acquisitions of properties located in other geographic areas.

Our current Eureka Hunter midstream operations and the expected future expansion of these operations, which include or will include natural gas gathering operations and a natural gas processing plant, subject us to additional governmental regulations.

The Company is currently constructing its Eureka Hunter pipeline, which will provide intrastate gas gathering services in support of the Company's and other upstream producers' operations in West Virginia and possibly Ohio. The Company has completed the first phase of the initial section of the pipeline and anticipates further expansion of the pipeline in 2011, which expansion will be determined by various factors, including the completion of construction, securing regulatory and governmental approvals, resolving any land management issues and connecting the pipeline to the producing sources of natural gas. The Company has also contracted for the construction of a gas processing facility which the Company anticipates will receive gas from the Eureka Hunter pipeline. Such facility is in the early stages of design and construction and is anticipated to be delivered to a site in West Virginia in the latter part of 2011.

The construction and operation of the Eureka Hunter pipeline and gas processing facility involve numerous regulatory, environmental, political and legal uncertainties beyond our control and require the expenditure of significant amounts of capital. There can be no assurance that these projects will be completed on schedule or at the budgeted cost, or at all. The operations of our gathering system, including the Eureka Hunter pipeline, in addition to the gas processing facility, are also subject to stringent and complex federal, state and local environmental laws and regulations. These laws and regulations can restrict or impact our business activities in many ways, including restricting the manner in which we dispose of substances, requiring remedial action to remove or mitigate contamination, and requiring capital expenditures to comply with control requirements. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where substances and wastes have been disposed or otherwise released. Moreover, there exists the possibility for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or wastes into the environment.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to our handling of natural gas and other petroleum products, air emissions related to our operations, historical industry operations including releases of substances into the environment, and waste disposal practices. For example, an accidental release from the Eureka Hunter pipeline or our gas processing facility under construction could subject us to substantial liabilities arising from environmental cleanup, restoration costs and natural resource damages, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover some or any of these costs from insurance.

Risks Related to Our Equity Securities

The price of our common stock has fluctuated substantially since it first became listed on a national securities exchange in August 2006, and may fluctuate substantially in the future.

The price of our common stock has fluctuated substantially since it first became listed on a national securities exchange in August 2006. From August 30, 2006 to February 15, 2011, the trading price at the close of the market (initially the American Stock Exchange and currently the NYSE) of our common stock ranged from a low of $0.20 per share to a high of $8.34 per share. We expect our common stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include:

- changes in oil and natural gas prices;
- variations in quarterly drilling, recompletions, acquisitions and operating results;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- additions or departures of key personnel;
- the level of our overall indebtedness;
- future issuances of our common stock and related dilution to existing stockholders; and
- the other risks and uncertainties described in this "Risk Factors" section and elsewhere in this report.

We may fail to meet the expectations of our stockholders or of securities analysts at some time in the future, and our stock price could decline as a result. Volatility or depressed market prices of our common stock could make it difficult for our stockholders to resell shares of our common stock when they want or at attractive prices.

The market for our common stock may not provide investors with sufficient liquidity or a market based valuation of our common stock.

Our common stock is traded on the NYSE under the symbol "MHR". On February 15, 2011, the last reported sale price of our common stock on the NYSE was $6.86 per share. The present volume of trading in our common stock may not provide investors sufficient liquidity in the event they wish to sell their shares of common stock. There can be no assurance that an active market for our common stock will be available for trading in large volumes. In addition, the stock market in general, and early stage public companies in particular, have experienced extreme price and volume fluctuations that have often been unrelated or disproportionate to the operating performance of such companies. If we are unable to further develop an active market for our common stock, our stockholders may not be able to sell our common stock at prices they consider to be fair or at times that are convenient for them, or at all.

We will likely issue additional common stock in the future, which would dilute our existing stockholders.

In the future we may issue additional securities up to our total authorized and unissued amounts, including shares of our common stock or securities convertible into or exchangeable for our common stock, resulting in the dilution of the ownership interests of our stockholders. We are authorized under our amended and restated certificate of incorporation to issue 150,000,000 shares of common stock and 10,000,000 shares of preferred stock with such designations, preferences and rights as may be determined by our board of directors. As of February 15, 2011, there were 76,462,082 shares of our common stock issued and outstanding and 4,000,000 shares of our Series C Preferred Stock issued and outstanding.

We have an effective shelf registration statement from which additional shares of our common stock and other securities can be issued. We may also issue additional shares of our common stock or securities convertible into or exchangeable for our common stock in connection with the hiring of personnel, future acquisitions or future private placements of our securities for capital raising purposes or for other business purposes. As described in this report, we will issue additional shares of our common stock in connection with our acquisitions of NGAS Resources, Inc. and NuLoch Resources Inc., if and when such acquisitions are completed. Future issuances of our common stock, or the perception that such issuances could occur, could have a material adverse effect on the price of our common stock at any given time.

Additionally, we are engaged in the issuance and sale of our common stock from time to time through a sales agent pursuant to an "at the market" (ATM) sales agreement between us and the sales agent. Sales of shares of our common stock, if any, by the sales agent will be made in privately negotiated transactions or in any method permitted by law deemed to be an ATM offering as defined in Rule 415 promulgated under the Securities Act, at negotiated prices, at prices prevailing at the time of sale or at prices related to such prevailing market prices, including sales made directly on the NYSE or sales made through a market maker other than on an exchange.

Our amended and restated certificate of incorporation, amended and restated bylaws, and Delaware law contain provisions that could make it more difficult for a third party to acquire us without the consent of our board of directors and our executive officers, who collectively beneficially owned approximately 7.5% of the outstanding shares of our common stock as of February 15, 2011.

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

- the ability of our board of directors to issue shares of our common stock and preferred stock without stockholder approval;
- the ability of our board of directors to make, alter, or repeal our bylaws without further stockholder approval;
- the requirement for advance notice of director nominations to our board of directors and for proposing other matters to be acted upon at stockholder meetings;

- requiring that special meetings of stockholders be called only by our chairman, by a majority of our board of directors, by our chief executive officer or by our president; and
- allowing our directors, and not our stockholders, to fill vacancies on the board of directors, including vacancies resulting from removal or enlargement of the board of directors.

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

As of February 15, 2011, our board of directors and executive officers collectively beneficially owned approximately 7.5% of the outstanding shares of our common stock. Although this is not a majority of our outstanding common stock, these stockholders, acting together, will have the ability to exert substantial influence over all matters requiring stockholder approval, including the election and removal of directors, any proposed merger, consolidation, or sale of all or substantially all of our assets and other corporate transactions.

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

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

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

We are able to issue shares of preferred stock with greater rights than our common stock.

Our amended and restated certificate of incorporation authorizes our board of directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from our stockholders. Any preferred stock that is issued may rank ahead of our common stock in terms of dividends, liquidation rights or voting rights. If we issue additional preferred stock, it may adversely affect the market price of our common stock.

Our assets are subject to liquidation preferences in favor of the holders of our Series C Preferred Stock, which will impact the rights of holders of our common stock if we liquidate.

We have issued and sold an aggregate of 4,000,000 shares of our Series C Preferred Stock. Under the certificate of designations of the Series C Preferred Stock, if we liquidate, holders of our Series C Preferred Stock are entitled to receive the repayment of their original investment, together with any accrued but unpaid dividends, before any payment is made to holders of our common stock.

Our outstanding warrants which are exercisable for shares of our common stock, may be exercised, which would dilute our existing common stockholders.

As of December 31, 2010, we had outstanding warrants that have a final maturity of 2012 exercisable for an aggregate of 963,034 shares of our common stock. Any such exercise will be dilutive to our existing stockholders.

The market price of our common stock could be adversely affected by sales of substantial amounts of our common stock and securities convertible into, or exchangeable for, shares of our common stock in the public markets and the issuance of shares of common stock and securities convertible into, or exchangeable for, shares of our common stock in future acquisitions.

Sales of a substantial number of shares of our common stock by us or by other parties in the public market, or the perception that such sales may occur, could cause the market price of our common stock to decline. In addition, the sale of such shares in the public market could impair our ability to raise capital through the sale of common stock or securities convertible into, or exercisable for, shares of common stock.

In addition, in the future, we may issue shares of our common stock and securities convertible into, or exchangeable for, shares of our common stock in furtherance of our acquisitions and development of assets or businesses. If we use our shares for this purpose, the issuances could have a dilutive effect on the value of our common stock, depending on market conditions at the time of such an event, the price we pay, the value of the assets or business acquired and our success in exploiting the properties or integrating the businesses we acquire and other factors.

Item 2. *PROPERTIES*

Appalachian Basin/Marcellus Shale

The Appalachian Basin is considered one of the most mature oil and natural gas producing regions in the United States. The Company made its entry into the Appalachian Basin through the acquisition of the assets of Triad Energy in February 2010. We recently expanded our acreage position and reserves with the acquisition of assets from affiliates of PostRock Energy Corporation in December 2010 and January 2011, which we refer to as the PostRock properties. In addition, on December 27, 2010, we announced the pending acquisition of NGAS which, if and when such acquisition is completed, will further expand our presence in the Appalachian Basin. As of February 15, 2011, the Company held approximately 91,870 net acres in the Appalachian Basin, including approximately 56,595 net acres overlying the Marcellus Shale area.

At December 31, 2010, proved reserves attributable to our Appalachian Basin area of operations on an SEC basis were 9.2 mmboe, of which 35% were oil and 43% were classified as proved developed producing. Using NYMEX strip prices, proved reserves were 9.6 mmboe at December 31, 2010. We operate 2,090 gross productive wells and exited 2010 with a production rate of approximately 1,575 boepd in the Appalachian Basin.

Our Appalachian Basin acreage is located in West Virginia, Ohio and Kentucky. The liquids rich gas and high btu content of the natural gas produced in the Company's core Marcellus Shale area in northwest West Virginia and southeastern Ohio, coupled with a location near the energy-consuming regions of the mid-Atlantic and northeastern United States, typically allow the Company to sell its natural gas at a premium to the benchmark price for natural gas on the NYMEX. Historically, producers in the Appalachian Basin developed oil and natural gas from shallow Mississippian age sandstone and Upper Devonian age shales with low permeability, which are prevalent in the region. Traditional shallow wells in the Appalachian Basin generally produce little or no water, contributing to a low cost of operation. However, in recent years, the application of lateral well drilling and completion technology has led to the development of the Marcellus Shale, transforming the Appalachian Basin into one of the country's premier natural gas reserves.

The productive limits of the Marcellus Shale cover a large area within New York, Pennsylvania, Ohio and West Virginia. This Devonian age shale is a black, organic rich shale deposit productive at depths between 5,500 and 6,000 feet and ranges in thickness from 50 to 80 feet. It is considered the largest natural gas field in the country. Marcellus Shale gas is best produced from hydraulically fractured horizontal wellbores. These horizontal laterals exceed 2,000 feet in length, and typically involve multistage fracturing completions.

As of February 14, 2011, we had approximately 56,595 net acres in the core Marcellus Shale area. Our Marcellus Shale acreage is principally located in Tyler, Pleasants, Doddridge, Wetzel and Lewis Counties, West Virginia. The Company operates 32 vertical Marcellus Shale wells and three horizontal Marcellus Shale wells defining the potential within our existing acreage. We also own conventional acreage in Pleasants County, West Virginia and in Nobel and Washington Counties, Ohio. As of February 14, 2011, approximately 75% of our leases in the Marcellus Shale area are held by production. Our shallow production comes from the Big Ingun, Berea, Devonian Shale and the Clinton/Medina Sands. We also believe that our acreage may have the possibility of producing from the Trenton-Black River and Huron formations. The Huron formation has also benefited from lateral well drilling technology. In addition to our Marcellus Shale acreage, we have significant enhanced waterflood oil recovery operations in Calhoun, Clay and Roane Counties, West Virginia, including our Granny's Creek Field, Richardson Unit and Tariff unit.

The PostRock properties acquired by us in December 2010 and January 2011 are 100% operated by Triad Hunter. The PostRock properties include a total of approximately 9,423 gross acres (6,758 net acres), comprising approximately 4,451 gross acres (2,225 net acres) in Wetzel County, West Virginia and approximately 4,972 gross acres (4,533 net acres) in Lewis County, West Virginia. The acquired acreage is located in the general proximity of Triad Hunter's existing Marcellus Shale acreage in Tyler, Pleasants and Doddridge Counties, West Virginia. The majority of future lease expirations across the acquired acreage can be extended through a manageable drilling program which is planned for early 2011. Our proved reserves at December 31, 2010 included approximately 1.94 mmboe associated with the PostRock properties acquired in December 2010.

The Company's first horizontal well in the natural gas liquids rich leg of the Marcellus Shale of northwestern West Virginia was the Weese Hunter #1001, located in Tyler County. The Company spud the Weese Hunter #1001 in late July 2010 and reached total vertical depth of approximately 6,510 feet in mid August 2010. A third party drilling rig commenced the horizontal leg in mid September 2010 and reached a horizontal length of approximately 4,028 feet. Total measured depth for the Weese Hunter #1001 is approximately 10,388 feet. A twelve stage frac job was successfully completed in December 2010. The Weese Hunter #1001 well initially tested at a production rate (IP) of 7.0 mmcfe per day with flowing tubing pressures of 2350 psi on a $^{22}/_{64}$ inch choke. The btu content of the well was measured at approximately 1,225. The Weese Hunter #1001 began producing into our Eureka Hunter pipeline system on December 22, 2010. The current EUR for the Weese Hunter #1001 is approximately 4 bcfe. The Company operates this well and owns a 100% working interest with a 84.3% net revenue interest.

The Company's second horizontal well in this area of the Marcellus Shale was the Weese Hunter #1003, located in Tyler County. The Company spud the Weese Hunter #1003 in October 2010 and reached total vertical depth of approximately 6,360 feet in November 2010. The well's horizontal leg extends approximately 2,984 feet. Total measured depth for the Weese Hunter #1003 is approximately 10,151 feet. A twelve stage frac job was successfully completed in January 2011. The Weese Hunter #1003 well initially tested at a production rate (IP) of 5.45 mmcfe per day. The Weese Hunter #1003 began producing into our Eureka Hunter pipeline system on January 24, 2011.

The Company's third horizontal well in this area of the Marcellus Shale was the Ormet #1-9H, located in Tyler County. The Company spud the Ormet #1-9H in October 2010 and reached total vertical depth of approximately 5,871 feet in October 2010. The drilling rig commenced the horizontal leg in mid November 2010 and reached a horizontal length of approximately 3,628 feet. Total measured depth for the Ormet #1-9H is approximately 9,944 feet. A twelve stage frac job was successfully completed in February 2011. The Ormet #1-9H well is expected to achieve first flow in late February 2011.

On January 25, 2011, NGAS and Triad Hunter entered into a participation agreement and related operating agreement for two horizontal wells required under an existing NGAS drilling commitment under a lease covering approximately 27,000 acres in the Amvest field. The participation agreement provides that the wells are to be drilled by NGAS for the account of Triad Hunter at cost, with NGAS receiving an overhead fee of $50,000 per well and Magnum Hunter receiving a put option on the wells, at cost.

We plan to significantly expand our Marcellus Shale program in 2011, drilling a minimum of 15 gross horizontal wells (12.5 net) from our inventory of over 439 identified drilling locations at a cost of approximately $60 million.

South Texas/Eagle Ford Shale

Our Eagle Ford Shale acreage is located in the oil window of the trend in Gonzales, Atascosa and Fayette Counties, Texas with estimated original oil in place of 20-40 mmbbls per section. Effective development of our Eagle Ford Shale assets depends on optimization of horizontal drilling and multi-stage reservoir stimulation. Increased lateral length, increased frac stages and proper frac fluid selection are also important factors in increasing

EURs and production rates. Initial production rates in the oil window are also dependent on gas oil ratios (GORs). Rock properties and fluid characteristics also can enhance deliverability and EURs.

The Eagle Ford Shale is a Cretaceous aged shale ranging in thickness of less than 50 feet to over 300 feet. The Eagle Ford Shale is present within the subsurface along the entire Gulf Coast of Texas and is productive within the majority of the trend, producing from the more brittle calcareous or dolomitic shale sections. The Eagle Ford Shale produces from depths that range from approximately 7,500 to 14,000 feet. The Eagle Ford Shale has become one of the newest emerging successful shale reserves in the country.

As of December 31, 2010, Magnum Hunter had 890.5 mbbls of oil and 463.9 mmcf of natural gas of net estimated ultimate recoverable reserves on an SEC basis associated with our Eagle Ford Shale properties.

As of February 1, 2011, we had approximately 23,075 net acres (47,664 gross) primarily targeting the Eagle Ford Shale oil window. We have currently identified approximately 100 horizontal Eagle Ford Shale drilling locations, of which less than 10% are currently classified as proved reserves. Our working interests vary from 50% in Gonzales, Lee and Fayette Counties, Texas to 96.75% in Atascosa County, Texas. We have budgeted an estimated $65 million in capital expenditures for 2011 for the drilling of 14 gross (7 net) horizontal wells targeting the Eagle Ford Shale oil window. The Company has focused in the up-dip oil trend of the Eagle Ford Shale (8,000 to 11,500 feet) to provide better economic metrics.

We entered into a joint venture with Hunt Oil Company covering an area of mutual interest (AMI) consisting of 28,187 gross acres and 26,822 net acres in Gonzales and Lavaca Counties, Texas, under which each company has a 50% ownership interest. Both parties agreed to work together within the AMI on an equal and joint basis through December 2014. Both companies have cross-assigned existing ownership interests in their respective lease acreage positions for both Lavaca and Gonzales Counties. Additionally, the parties will share all future leasing, exploration, drilling, completion and development costs and other expenses in the AMI on an equal basis. Each company has also agreed to allow the other to be the designated operator for all wells on lease acres contributed to the AMI by the other. Both companies intend that all new wells to be drilled under the joint venture will be horizontal Eagle Ford Shale wells.

We also have a second joint venture with a private independent oil and gas company in the Eagle Ford Shale area. The joint venture covers an AMI consisting of approximately 4,000 gross acres and 2,000 net acres of certain specific lease acreage positions currently owned by the Company and the other party in Gonzales and Lavaca Counties, Texas. Both parties agreed to work together within the AMI on an equal basis for all future leasing, exploration, drilling, completion and development costs and other expenses. We are the operator under the joint venture. All wells under the joint venture will be horizontal Eagle Ford Shale wells. The Company and the other party will jointly drill a minimum of two wells in the AMI.

We have an active drilling program in the Peach Creek Field, located in southeastern Gonzales County near the towns of Moulton and Shiner, Texas. The Company has an average working interest of 50% and net revenue interest of 38.3% in the Peach Creek Field.

The Company has an average working interest of 96.75% and net revenue interest of 72.56% in the Alright area of the Eagleville Field in southwestern Atascosa County, near Charlotte, Texas. This area is central to an active Eagle Ford Shale area called the four corners, which includes acreage in Atascosa, Frio, McMullen and LaSalle Counties, Texas.

The Company's first well drilled in the Eagle Ford Shale oil window was the Gonzo Hunter #1-H in Gonzales County, Texas. The well was spud on June 10, 2010 and was drilled to a true vertical depth of 9,750 feet plus 4,365 horizontal feet. After a successful frac job, the well had an initial production rate of 605 boepd and 412 bbls per day of water. At year end 2010, the Gonzo Hunter #1-H was flowing to production without artificial lift at approximately 186 bopd, 123 mcfpd and 54 bbls per day of water. The well had produced approximately 24,000 bbls of oil as of December 31, 2010. Magnum Hunter currently estimates the gross economic ultimate recovery for the Gonzo Hunter #1-H to be 362,000 boe. Magnum Hunter operates the well and owns a 50% working interest.

The Gonzo Hunter North #1-H was spud on December 31, 2010, and is located approximately one mile northeast of the Gonzo Hunter #1-H. The well was drilling ahead at a vertical depth of approximately 9,245 feet at December 31, 2010. Magnum Hunter operates the well and owns a 50% working interest. We anticipate that the Gonzo Hunter North #1-H will be fracture stimulated in February 2011.

The Company's Southern Hunter #1-H is located approximately seven miles southwest of the Gonzo Hunter #1-H. The well was spud on October 14, 2010 and was drilled to a true vertical depth of 11,779 feet plus 4,460 horizontal feet. After a 14 stage frac job, flowback commenced on January 7, 2011. In early January 2011, the Southern Hunter #1-H was flowing to production at approximately 1,335 boe per day and 212 bbls per day of water on a 13/64 inch choke with flow tubing pressure of 4,300 psi. Based on current production characteristics, the Company estimates the Southern Hunter #1-H's gross economic ultimate recovery to be in the 500,000 boe range. Magnum Hunter operates the well and owns a 50% working interest.

On November 2, 2010, the Cinco Ranch #2-H well was spud. The well, located in Gonzales County, has been drilled to a true vertical depth of 10,025 feet and an additional 5,541 feet horizontally. The well is scheduled for a March 2011 frac job. Magnum Hunter is a 50% working interest owner in the Cinco Ranch #2-H well. Hunt Oil Company is the operator and owns the remaining 50% working interest.

The Cinco Ranch #1-H was spud on December 13, 2010. The well, located in Gonzales County, was drilling ahead at December 31, 2010. The drilling rig was released in January 2011 after drilling to a true vertical depth of 9,667 feet plus 4,683 horizontal feet. Magnum Hunter is a 50% working interest owner in the Cinco Ranch #1-H well. Hunt Oil Company is the operator and owns the remaining 50% working interest.

The Company spud the Furrh #1-H well in early February 2011. This well is located in Gonzalez County. The Company operates the Furrh #1-H well and owns a 50% working interest.

The Company's first well in Atascosa County within the Eagle Ford Shale is the Lagunillas Camp #1-H. The well was spud on August 12, 2010 and was drilled to a true vertical depth of 8,350 feet plus 5,050 horizontal feet. After a 15 stage frac job, the well had an initial production rate of 340 boepd and 750 bbls per day of water. At December 31, 2010, the Lagunillas Camp #1-H was flowing to production with no artificial lift at approximately 216 bbls of oil and 742 bbls of water per day. Magnum Hunter operates the Lagunillas Camp #1-H well and owns a 96.875% working interest.

Magnum Hunter's second well in Atascosa County within the Eagle Ford Shale is the Lagunillas Camp #2-H. The well was spud on September 15, 2010 and was drilled to a true vertical depth of 8,350 feet plus 4,650 horizontal feet. At December 31, 2010, the Lagunillas Camp #2 well was producing approximately 147 bopd, 66 mcfpd and 275 bbls of water per day. The well had produced approximately 8,600 bbls of oil as of December 31, 2010. The Company operates the Lagunillas Camp #2-H well and owns a 96.875% working interest.

Williston Basin/Bakken Shale

At December 31, 2010, the Company owned an approximately 43% average non-operated working interest in 15 fields located in the Williston Basin in North Dakota comprising 151 wells and approximately 15,000 gross (6,540 net) acres. Approximately 90% of these leases, which are located in Burke, Renville, Ward, Bottineau and McHenry Counties in North Dakota, are held by production. As of December 31, 2010, our proved reserves on an SEC basis were an estimated 2.5 mmboe with approximately 96% and 90% of our reserves and production, respectively, consisting of oil. As of December 31, 2010, on a NYMEX strip basis, our proved reserves were 2.7 mmboe. At December 31, 2010, we had a production exit rate of approximately 392 boepd from our North Dakota properties.

Re-pressurization efforts with respect to our North Dakota properties commenced in November 2002, which have resulted in the ability to begin secondary recovery efforts through conventional and horizontal drilling activities in seven of the 15 producing fields. We have identified approximately 66 horizontal drilling locations.

On January 19, 2011, the Company entered into a definitive agreement to acquire NuLoch, which, if and when such acquisition is completed, will significantly expand our presence in the Williston Basin with 71,600 net acres and 267 net identified drilling locations. The Company has positioned itself to explore this liquids rich region in North America and plans to use NuLoch as an initial platform to acquire and develop reserves and production in the Williston Basin in 2011.

The Williston Basin is spread across North Dakota, Montana and parts of southern Canada with the United States portion of the basin encompassing approximately 143,000 square miles. The basin produces oil and natural gas from numerous producing horizons including the Madison, Bakken, Three Forks/Sanish and Red River formations.

The Bakken formation is a Devonian age shale found within the Williston Basin. The North Dakota Geological Survey and Oil and Gas Division estimates that the Bakken formation is capable of generating between 271 and 500 billion bbls of oil. The Bakken formation underlies portions of North Dakota and Montana and is generally found at vertical depths of 9,000 to 10,500 feet. Below the Lower Bakken Shale lies the Three Forks/Sanish formation, and the Three Forks Shale has also proven to contain reservoir rock. The Three Forks/Sanish typically consists of interbedded dolomites and shale with local development of a discontinuous sandy member at the top, known as the Sanish sand. Crude oil production from the Bakken Shale and Three Forks/Sanish reservoirs is made possible through the combination of advanced horizontal drilling and fracture stimulation technology. Combining these two technologies to produce crude oil from the Bakken formation began to evolve around the year 2000. Horizontal wells in these formations are typically drilled on 320 acre, 640 acre or 1,280 acre spacing with horizontal laterals extending 4,500 to 9,500 feet into the reservoir. Fracture stimulation techniques vary but most commonly utilize multi-stage mechanically diverted stimulations using un-cemented liners and packers.

Other Properties

South Louisiana / East Chalkley — Our East Chalkley field is located in Cameron Parish, Louisiana. The unit consists of approximately 714 gross acres. This developmental project is an exploitation of bypassed oil reserves remaining in a natural gas field located at depths between 9,300 and 9,400 feet. At December 31, 2010, proved reserves on an SEC basis were 274 mboe, consisting of 88% oil and 47% proved developed. At December 31, 2010, proved reserves on a NYMEX strip basis were 277 mboe. The Company operates East Chalkley and owns an approximate 62% working interest and approximate 42.7% net revenue interest. We have not allocated any capital to this project for 2011 and are actively seeking to divest this non-core asset.

Other — The Company has an interest in the Surprise Project which is located in Nacogdoches County, Texas with natural gas potential from multiple horizons including James Lime, Pettit, Travis Peak, Expanded Bossier, Cotton Valley, and Haynesville Shale formations. The prospect is operated by Goodrich Petroleum Corporation. The prospect area consists of approximately 4,796 gross (479 net) acres, and we have a 10% working interest and a 7.4% net revenue interest in the prospect. In addition, we have approximately 157,758 gross (13,371 net) undeveloped acres in New Mexico, Kentucky and Utah. We currently do not plan to allocate any capital to these prospects or areas for 2011.

Midstream Assets

The acquisition of assets from Triad Energy included important infrastructure assets for the effective development of the Company's Marcellus Shale unconventional resources. With increased drilling activity in the region, relying on third party oilfield service providers and pipeline operators can be costly. Access to a pipeline system is vital to flow natural gas to sales and often is a deciding factor in drilling and production decisions. The summary below provides a brief overview of the midstream services we operate and control. We anticipate these assets will generate an attractive revenue stream as we actively market them to third party producers in the Appalachian Basin.

The Eureka Hunter pipeline consists of approximately 182 miles of pipeline, gathering systems and/or rights-of-way located in northern West Virginia, in the Marcellus Shale. The rights-of-way run through Pleasants, Tyler, Ritchie, Wetzel, Marion, Harrison, Doddridge, Lewis and Monongalia Counties. We are currently constructing a new 20 inch high-pressure pipeline with up to 200 mmcfpd of throughput capacity. The first pipeline section of six miles was turned to sales on December 22, 2010. The next section of the pipeline of approximately 10 miles, which together with the initial six mile section comprising the first phase, is expected to be completed by June 30, 2011. We expect to have sufficient capacity to gather significant quantities of Company-produced natural gas from our Marcellus Shale development program, as well as third-party gas. We have budgeted $25 million to this project for 2011 which will be used for the construction of approximately six miles of main line and 12 miles of laterals.

In December 2010, the Company entered into an agreement for the construction of a new 200 mmcf per day capacity cryogenic natural gas processing plant. The processing plant will process natural gas and natural gas liquids gathered on the Eureka Hunter pipeline. Installation and hookup of the plant will begin upon delivery of the plant, scheduled for October 2011. The plant is expected to be operational by mid-year 2012. With the Company's first section of the Eureka Hunter pipeline system operational, the purchase of the plant furthers the Company's goal of becoming a fully integrated producer, gas gatherer and processor in this region. The plant will allow us to not only gather and process our equity natural gas, but also to provide a conduit for other producers in the area. We anticipate funding capital requirements for the plant through a combination of a partnership with an industry participant and/or project financing. Our pending acquisition of NGAS contemplates the restructuring of an existing out-of-market gas gathering and transportation agreement between NGAS and a third party, and as part of the restructuring such third party would be granted a limited option to acquire a 50% ownership interest in the processing plant. We are also discussing funding arrangements for the plant with other potential industry partners.

Equipment and Services

Alpha Hunter Drilling — As part of the acquisition of the Triad Energy assets, we acquired oilfield service equipment which is operated by our subsidiary, Alpha Hunter Drilling, LLC. This equipment consists primarily of three drilling rigs, a workover rig and heavy machinery, which are used in our operations and also those of third parties. We anticipate using our rigs to drill the vertical portions of our Marcellus Shale wells and then switching to larger rigs for the horizontal sections. This flexibility is expected to reduce the overall drilling costs, as well as improve the timing of drilling activity. As of February 14, 2011, two of our drilling rigs were under multi-well drilling contracts to large producers in the area. The third drilling rig will be utilized for drilling the top hole for our 2011 Marcellus Shale drilling program and will be leased to third party operators on the spot market.

Hunter Disposal — Typically, Marcellus Shale wells produce significant amounts of water that, in most cases, require disposal. Producers often remove the water in trucks for proper disposal in approved facilities. While this method has been the only option to many producers in the Appalachian Basin, it adds a significant operating burden and increases costs. Our subsidiary, Hunter Disposal LLC, owns and operates a salt water disposal facility located in Ohio, with current capacity of approximately 120,000 barrels of water per month. Additionally, Hunter Disposal owns and operates a second commercial salt water disposal facility located in the Primrose Field in Lee County, Kentucky. This disposal facility averages 45,000 barrels of water per month. This facility has a capacity for increased disposal up to 60,000 barrels of water per month with minimal capital requirements. In addition to utilizing our disposal facilities to reduce our operating costs and more importantly provide a cost-efficient option to dispose of water generated from our Marcellus Shale drilling program, we market our disposal capabilities to third party operators.

Reserves

Our oil and gas properties are primarily located in (i) the Appalachian Basin in West Virginia, Ohio and Kentucky, with substantial acreage in the Marcellus Shale area in West Virginia; (ii) Texas, including substantial acreage in the Eagle Ford Shale area; (iii) the Williston Basin in North Dakota; and (iv) southern Louisiana. We currently do not have any delivery commitments with regard to our future oil and gas production. Cawley, Gillespie & Associates, Inc., independent petroleum consultants, which we refer to as CGA, has estimated our oil and natural gas reserves and the present value of future net revenues therefrom as of December 31, 2010. Those estimates were determined based on prices and costs as of or for the twelve month period ended December 31, 2010. Since January 1, 2010, we have not filed, nor were we required to file, any reports concerning our oil and gas reserves with any federal authority or agency, other than the SEC.

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and estimates of reserve quantities and values must be viewed as being subject to significant change as more data about the properties become available.

Proved Reserves

In December 2008, the SEC released its finalized rule for "Modernization of Oil and Gas Reporting." The new rule requires disclosure of oil and gas proved reserves by significant geographic area, using the arithmetic 12-month average beginning-of-the-month price for the year, as opposed to using year-end prices as was practiced in all previous years. The rule also allows for the use of reliable technologies to estimate proved oil and gas reserves, contingent on demonstrated reliability in conclusions about reserve volumes. Under the new rules, companies are required to report on the independence and qualifications of their reserve preparers or auditors, and file reports when a third-party is relied upon to prepare reserve estimates or conduct a reserve audit. The following table sets forth our estimated proved reserves based on the new SEC rules as defined in Rule 4.10(a) of Regulation S-X and Item 1200 of Regulation S-K.

Category	Net Reserves (SEC Prices at 12/31/10) Oil (mbbls)	NGL (barrels)	Gas (mmcf)	PV-10 ($mm)
Proved Developed	3,720	—	18,888	$111.8
Proved Undeveloped	3,104	—	20,564	$ 66.0
Total Proved	**6,824**	—	**39,452**	**$177.8**

The table below summarizes our proved reserves, based on NYMEX futures strip pricing as of December 31, 2010.

Category	Net Reserves (Based on NYMEX Futures Prices at 12/31/10) Oil (mbbls)	NGL (barrels)	Gas (mmcf)	PV-10 ($mm)
Proved Developed	3,975	—	20,577	$144.9
Proved Undeveloped	3,632	—	21,167	$ 97.7
Total Proved	**7,607**	—	**41,744**	**$242.6**

All of our reserves are located within the continental United States. Reserve estimates are inherently imprecise and remain subject to revisions based on production history, results of additional exploration and development, prices of oil and natural gas and other factors. Please read "Item 1A. Risk Factors — Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves". You should also read the notes following the table below and our consolidated financial statements for the year ended December 31, 2010 in conjunction with the following reserve estimates.

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

	2010	2009	2008
Description			
Proved Developed Reserves			
Oil (bbls)	3,720,300	1,694,700	1,092,730
NGLs (bbls)	—	361,000	301,577
Natural Gas (mcf)	18,887,700	4,952,500	2,549,496
Proved Undeveloped Reserves			
Oil (bbls)	3,104,000	2,126,800	769,309
NGLs (bbls)	—	426,000	245,636
Natural Gas (mcf)	20,564,200	4,411,700	1,703,450
Total Proved Reserves (boe)(1)(2)	**13,399,700**	**6,169,200**	**3,118,076**
PV-10 Value ($mm)(3)	$ 177.8	$ 65.6	$ 21.0
Standardized Measure ($mms)	$ 128.0	$ 47.4	$ 15.6

(1) The estimates of reserves in the table above conform to the guidelines of the SEC. Estimated recoverable proved reserves have been determined without regard to any economic impact that may result from our financial derivative activities. These calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry. The reserve information shown is estimated. The certainty of any reserve estimate is a function of the quality of available geological, geophysical, engineering and economic data, and the precision of the engineering and geological interpretation and judgment. The estimates of reserves, future cash flows and present value are based on various assumptions, and are inherently imprecise.

Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

(2) We converted natural gas to oil equivalent at a ratio of six mcf to one boe.

(3) Represents the present value, discounted at 10% per annum (PV-10), of estimated future cash flows before income tax of our estimated proved reserves. The estimated future cash flows set forth above were determined by using reserve quantities of proved reserves and the periods in which they are expected to be developed and produced based on prevailing economic conditions. The estimated future production is priced based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December 2010, using $79.43 per bbl and $4.37 per mmbtu and adjusted by lease for transportation fees and regional price differentials. Management believes that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies.

As of December 31, 2010, our proved undeveloped reserves on an SEC basis totaled 3.1 mmbo of crude oil and 20.6 bcf of natural gas for a total of 6.5 mmboe. Changes in PUDs that occurred during the year were due to increased drilling activity in our Eagle Ford Shale and Marcellus Shale areas of operation.

The following table summarizes the changes in our proved reserves for the year ended December 31, 2010:

Proved Reserves (mboe)	For the Year Ended December 31, 2010
Proved reserves — beginning of year	6,169.2
Revisions of previous estimates	(22.2)
Improved recovery	0.0
Extensions and discoveries	3,194.1
Production	(588.9)
Purchases of reserves in place	7,037.1
Sales of reserves in place	(2,389.6)
Proved reserves — end of year	13,399.7
Proved developed reserves — beginning of year	2,880.7
Proved developed reserves — end of year	5,842.4

Recent SEC Rule-Making Activity

In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserves reporting requirements. The most significant amendments to the requirements included the following:

- *Commodity Prices:* Economic producibility of reserves and discounted cash flows are now based on a 12-month average commodity price unless contractual arrangements designate the price to be used.
- *Disclosure of Unproved Reserves:* Probable and possible reserves may be disclosed separately on a voluntary basis.
- *Proved Undeveloped Reserve Guidelines:* Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.
- *Reserves Estimation Using New Technologies:* Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.
- *Reserves Personnel and Estimation Process:* Additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserves estimation process. We are also required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.

- *Non-Traditional Resources:* The definition of oil and gas producing activities has expanded and focuses on the marketable product rather than the method of extraction.

Reserve Estimation

CGA evaluated our oil and gas reserves on a consolidated basis as of December 31, 2010. The technical persons responsible for preparing our proved reserves estimates meet the requirements with regard to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. CGA does not own an interest in any of our properties and are not employed by us on a contingent basis.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with CGA to ensure the integrity, accuracy and timeliness of the data used to calculate our proved oil and gas reserves. Our internal technical team members meet with CGA periodically throughout the year to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to CGA for our properties such as ownership interest; oil and gas production; well test data; commodity prices; and operating and development costs. The preparation of our proved reserve estimates is completed in accordance with our internal control procedures, which include the verification of input data used by CGA, as well as extensive management review and approval. All of our reserve estimates are reviewed and approved by our executive vice president of operations and our vice president of reservoir engineering. Our executive vice president of operations holds a B.S. in petroleum engineering from the University of Louisiana-Lafayette with more than 35 years of experience and is a member of the National Society of Professional Engineers, Society of Petroleum Engineers, and the Society of Petroleum Evaluation Engineers. Our vice president of reservoir engineering holds a B.S. in chemical engineering from Ohio State University with more than 28 years of experience, was a member of the University of Texas External Advisory Committee for Petroleum and Geosystems Engineering and has served in various officer and board of director capacities for the Society of Petroleum Engineers.

The technologies used in the estimation of our proved reserves are commonly employed in the oil and gas industry and include seismic and micro-seismic operations, reservoir simulation modeling, analyzing well performance data and geological and geophysical mapping.

Acreage and Productive Wells Summary

The following tables set forth, for our continuing operations, our gross and net acreage of developed and undeveloped oil and natural gas leases and our gross and net productive oil and natural gas wells as of December 31, 2010.

	Developed Acreage(1)		Undeveloped Acreage(2)		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Appalachia	70,803	62,652	110,449	33,723	181,252	96,375
North Dakota	15,200	6,536	3,411	1,116	18,611	7,652
Texas	6,993	1,916	51,152	24,229	58,145	26,145
Other	714	443	90,000	8,866	90,714	9,309
Total	**93,710**	**71,547**	**255,012**	**67,934**	**348,722**	**139,481**

(1) Developed acreage is the number of acres allocated or assignable to producing wells or wells capable of production.

(2) Undeveloped acreage is lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage includes proved reserves.

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

	Producing Oil Wells		Producing Gas Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Appalachia	1,398.0	1,375.6	692.0	638.6	2,090.0	2,014.2
North Dakota	151.0	70.9	0.0	0.0	151.0	70.9
Texas	4.0	2.8	15.0	2.2	19.0	5.0
Other	2.0	1.3	0.0	0.0	2.0	1.3
Total	**1,555**	**1,451**	**707**	**641**	**2,262**	**2,091**

The following table sets forth, for our continuing operations, the gross and net acres of undeveloped land subject to leases summarized in the preceding table that will expire during the periods indicated if not ultimately held by production by drilling efforts:

Year Ending December 31,	Expiring Acreage	
	Gross	Net
2011	12,425	8,848
2012	20,267	12,687
2013	25,865	20,757
2014	31,156	21,864
Total	**89,713**	**64,156**

Drilling Results

The following table summarizes our drilling activity for the past three years. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells. All of our drilling activities were conducted on a contract basis by independent drilling contractors, except for our activities in the Marcellus Shale where we also utilize the drilling equipment of our subsidiary, Alpha Hunter Drilling.

	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive	8	6.67	3	0.70	25	2.45
Unproductive	0	0.00	1	0.10	11	2.20
Total	**8**	**6.67**	4	**0.80**	**36**	**4.65**
Developmental Wells:	67	6.70	27	3.80	8	1.41
Total Wells:						
Productive	75	13.37	30	4.50	33	3.86
Unproductive	0	0.00	1	0.10	0	0.00
Total	**75**	**13.37**	**31**	**4.60**	**33**	**3.86**
Success Ratio(1)	100.0%	100.0%	96.8%	97.8%	100.0%	100.0%

(1) The success ratio is calculated as follows: (total wells drilled — non-productive wells — wells awaiting completion)/(total wells drilled — wells awaiting completion).

As of February 15, 2011, we had 1 gross (0.5 net) wells in the process of drilling or completing.

Oil and Gas Production, Prices and Costs

The following table shows the approximate net production attributable to our oil and gas interests, the average sales price and the average lease operating expense attributable to our total oil and gas production and for certain segments of our operations as required by SEC rules. Production and sales information relating to properties acquired is reflected in this table only since the closing date of the acquisition and may affect the comparability of the data between the periods presented. Property disposed of that is treated as discontinued operations has been excluded from such periods.

	Years Ended December 31,		
	2010	2009	2008
Sistersville(1)			
Oil Production (Bbls)	3,896.0	—	—
Natural Gas Production (Mcf)	256,157.0	—	—
NGL Production (Bbls)	—	—	—
Total Production (Boe)	46,588.8	—	—
Oil Average Sales Price	$ 71.80	—	—
Natural Gas Average Sales Price	$ 5.91	—	—
NGL Average Sales Price	—	—	—
Average Lease Operating Expense per Boe	$ 10.59	—	—
Mohall(2)			
Oil Production (Bbls)	38,034.7	29,532.1	22,748.0
Natural Gas Production (Mcf)	—	—	—
NGL Production (Bbls)	—	—	—
Total Production (Boe)	38,034.7	29,532.1	22,748.0
Oil Average Sales Price	$ 69.70	$ 55.30	$ 85.32
Natural Gas Average Sales Price	—	—	—
NGL Average Sales Price	—	—	—
Average Lease Operating Expense per Boe	$ 22.96	$ 20.79	$ 28.26
Total Company			
Oil Production (Bbls)	316,119.6	114,590.0	110,718.9
Natural Gas Production (Mcf)	952,174.7	191,151.0	130,370.5
NGL Production (Bbls)	—	—	—
Total Production (Boe)	474,817.3	146,449.0	132,447.4
Oil Average Sales Price	$ 72.41	$ 53.56	$ 86.92
Natural Gas Average Sales Price	$ 5.07	$ 2.46	$ 4.36
NGL Average Sales Price	—	—	—
Average Lease Operating Expense per Boe	$ 21.90	$ 26.48	$ 30.42

(1) These properties were part of the assets acquired from Triad Energy in 2010, which are located in West Virginia.

(2) These properties are part of our non-operated properties in the Williston Basin in North Dakota.

Title to Properties

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

- customary royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- development obligations under oil and gas leases;
- net profit interests;
- overriding royalty interests;
- non-surface occupancy leases; and
- lessor consents to placement of wells.

Non-GAAP Measures: Reconciliation to Standardized Measure

This annual report contains certain financial measures that are non-GAAP measures. We have provided reconciliations within this report of the non-GAAP financial measures to the most directly comparable GAAP financial measures. These non-GAAP financial measures should be considered in addition to, but not as a substitute for, measures for financial performance prepared in accordance with GAAP that are presented in this report.

PV-10 is the present value of the estimated future cash flows from estimated total proved reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of future income taxes. The estimated future cash flows are discounted at an annual rate of 10% to determine their "present value". We believe PV-10 to be an important measure for evaluating the relative significance of our oil and gas properties and that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and investors in evaluating oil and gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating the Company. We believe that PV-10 is a financial measure routinely used and calculated similarly by other companies in the oil and gas industry. However, PV-10 should not be considered as an alternative to the standardized measure as computed under GAAP.

The standardized measure of discounted future net cash flows relating to our total proved oil and gas reserves is as follows (in thousands):

	As of December 31, 2010 (Unaudited)
Future cash inflows	$ 709,788
Future production costs	(253,544)
Future development costs	(77,216)
Future income tax expense	(88,233)
Future net cash flows	290,795
10% annual discount for estimated timing of cash flows	(162,836)
Standardized measure of discounted future net cash flows related to proved reserves	$ 127,959
Reconciliation of Non-GAAP Measure	
PV-10	$ 177,814
Less: Income taxes	
Undiscounted future income taxes	(88,233)
10% discount factor	38,378
Future discounted income taxes	(49,855)
Standardized measure of discounted future net cash flows	$ 127,959

Item 3. *LEGAL PROCEEDINGS*

We are not a party to any legal proceedings which management believes will have a material adverse effect on our consolidated results of operations or financial condition.

Item 4. *[REMOVED AND RESERVED]*

PART II

Item 5. *MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASE OF EQUITY SECURITIES*

Common Stock Trading Summary

Our common stock trades on the NYSE under the symbol "MHR." Prior to January 3, 2011, our common stock traded on the NYSE Amex (formerly the American Stock Exchange). The following table summarizes the high and low reported sales prices on days in which there were trades of our common stock on the NSYE Amex for each quarterly period for the last two fiscal years. On February 15, 2011, the last reported sale price of our common stock, as reported on the NYSE, was $6.86 per share.

	High	Low
2010:		
First quarter	$3.29	$1.50
Second quarter	5.49	3.00
Third quarter	4.85	3.75
Fourth quarter	8.05	3.87
2009:		
First quarter	$0.65	$0.21
Second quarter	0.84	0.20
Third quarter	1.43	0.54
Fourth quarter	2.24	1.20

Holders

On February 16, 2011, based on information from our transfer agent, Nevada Agency and Transfer Company, the number of holders of record of our common stock was 154. Effective February 21, 2011, American Stock Transfer & Trust Company, LLC will become the transfer agent for both our common stock and Series C Preferred Stock.

Dividends

We have not paid any cash dividends on our common stock since our inception and do not contemplate paying dividends on our common stock in the foreseeable future. Also, we are restricted from declaring or paying any cash dividends on our common stock under our senior credit facility. It is anticipated that earnings, if any, will be retained for the future operation of our business.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information with respect to our common shares issuable under our equity compensation plans as of December 31, 2010:

	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights(a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights(b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a))(c)
Equity compensation plans approved by security holders	9,079,356	$3.69	5,248,827
Equity compensation plans not approved by security holders	4,000,000	$0.37	—
Total	13,079,356	$2.65	5,248,827

The Company's stock incentive plan provides for the grant of stock options, shares of restricted stock, unrestricted shares of stock, performance stock and stock appreciation rights. Awards under the stock incentive plan may be made to any employee, officer, or director of the Company or any subsidiary or to consultants and advisors to the Company or any subsidiary. For additional information regarding our stock incentive plan, see note 9 to our consolidated financial statements.

Recent Sales of Unregistered Securities

During the year ended December 31, 2010, the Company sold from time to time an aggregate of 7,536,654 shares of its common stock pursuant to the exercise of certain warrants, as follows:

(a) The Company sold an aggregate of 5,722,650 shares of common stock pursuant to the exercise of certain warrants issued by the Company in 2005, at an exercise price of $2.00 per share, for total gross proceeds of approximately $11.4 million. The warrants were issued by the Company in connection with a private placement by the Company of units, consisting of shares of common stock and warrants to purchase shares of common stock, to fund the purchase of certain assets by the Company.

(b) The Company sold an aggregate of 251,500 shares of its common stock pursuant to the exercise of certain warrants issued by the Company in 2006, at an exercise price of $3.00 per share, for total gross proceeds of approximately $754,500. The warrants were issued by the Company in connection with a private placement by the Company of units, consisting of shares of common stock and warrants to purchase shares of common stock, to fund the purchase of certain assets by the Company.

(c) The Company sold an aggregate of 1,562,504 shares of common stock pursuant to the exercise of certain warrants issued by the Company in November 2009, at an exercise price of $2.50 per share, for total gross proceeds of approximately $3.9 million. The warrants were issued by the Company in connection with an offering by the Company of units, consisting of shares of common stock and warrants to purchase shares of common stock, to a limited number of investors for cash, which was registered under the Securities Act. These investors consisted of certain directors and officers of the Company and certain of their friends and associates.

In addition:

(a) On May 12, 2010, the Company issued 7,500 shares of common stock to a former employee of the Company pursuant to his exercise of a stock option granted to him under the Company's stock incentive plan. The Company received proceeds from the exercise of $8,775.

(b) On February 3, 2010 and May 26, 2010, the Company issued an aggregate of 30,869 and 15,193 shares, respectively, of common stock to its non-management directors as payment of meeting fees owed to the directors for attendance at board and committee meetings. These shares were issued under the Company's stock incentive plan.

(c) On June 7, 2010, the Company issued 1,000,000 shares of common stock pursuant to the conversion by a shareholder of 1,000,000 shares of the Company's Series B Convertible Preferred Stock, in accordance with the terms of the preferred stock.

All the shares described above were issued or sold by the Company in reliance on the exemption from registration afforded by Section 4(2) of the Securities Act and/or Regulation D promulgated thereunder.

Repurchases of Common Stock

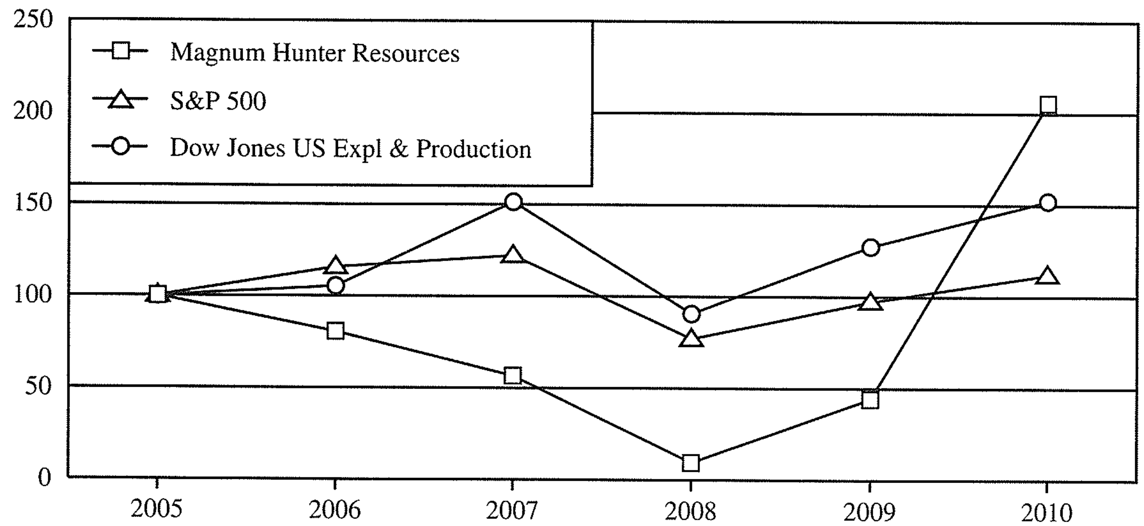
During September 2010, the Company purchased an aggregate of 153,300 shares of its common stock in the open market at an average purchase price of $3.94 per share to be used to fund potential future common stock contributions to employees of the Company and its subsidiaries pursuant to the Company's 401(k) Employee Stock Ownership Plan.

Share Performance Graph

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filings under the Securities Act or Exchange Act, except to the extent that the Company specifically incorporates it by reference into such filing.

The following graph illustrates changes over the five-year period ended December 31, 2010 in cumulative total stockholder return on our common stock as measured against the cumulative total return of the S & P 500 Index and the Dow Jones U.S. Exploration and Production Index. The results assume $100 was invested on December 31, 2005, and that dividends were reinvested.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN



	December 31,					
	2005	**2006**	**2007**	**2008**	**2009**	**2010**
Magnum Hunter Resources	100.00	80.56	56.56	9.42	44.28	205.70
S & P 500	100.00	115.79	122.16	76.96	97.33	111.99
Dow Jones US Expl & Production	100.00	105.37	151.39	90.65	127.42	152.32

Item 6. *SELECTED FINANCIAL DATA*

	2010	2009	2008	2007	2006
	Year Ended December 31, (In thousands, except per-share data)				
Income Statement Data					
Revenues	$ 32,724	$ 6,844	$ 11,590	$ 6,638	$ 1,516
Net loss from continuing operations	(22,257)	(15,569)	(9,468)	(5,781)	(3,858)
Income/(loss) from discontinued operations	8,457	445	2,582	242	(41)
Net loss	(13,800)	(15,124)	(6,886)	(5,539)	(3,899)
Dividends on preferred stock	(2,467)	(26)	(734)	(511)	—
Net loss attributable to common shareholders	$ (16,267)	$(15,150)	$ (7,621)	(6,050)	(3,899)
Basic and Diluted Earnings (Loss) Per Share					
Continuing operations	$ (0.38)	$ (0.40)	$ (0.28)	$ (0.30)	$ (0.19)
Discontinued operations	0.13	0.01	0.07	0.02	(0.01)
Net loss per share	$ (0.25)	$ (0.39)	$ (0.21)	$ (0.28)	$ (0.20)
Statement of Cash Flows Data					
Net cash provided by (used in)					
Operating activities	$ (1,167)	$ 3,372	$ 3,437	$ 854	$ (755)
Investing activities	(118,281)	(16,624)	(10,379)	(29,964)	(6,590)
Financing activities	117,720	9,413	(2,338)	40,225	8,212
Balance Sheet Data					
Cash and cash equivalents	$ 554	$ 2,282	$ 6,121	$ 15,400	$ 4,285
Other current assets	12,572	4,591	4,059	3,329	103
Property, equipment, net, successful efforts method	232,601	46,410	39,134	42,482	3,974
Other assets	3,240	13,301	12,351	5,152	2,586
Total assets	$ 248,967	$ 66,584	$ 61,665	$ 66,363	$10,948
Current liabilities	$ 44,235	$ 6,219	$ 3,497	$ 14,274	$ 218
Long-term debt	26,019	13,000	21,500	—	—
Other long-term liabilities	5,155	2,673	1,590	2,108	31
Redeemable preferred stock	70,236	5,374	—	7,232	—
Shareholders' equity	103,322	39,318	35,078	42,749	10,699
Total liabilities and shareholders' equity	$ 248,967	$ 66,584	$ 61,665	$ 66,363	$10,948

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

The following discussion is intended to assist you in understanding our results of operations and our financial condition. Our consolidated financial statements and the accompanying notes included elsewhere in this report contain additional information that should be referred to when reviewing this material. Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, which could cause actual results to differ from those expressed. See "Cautionary Note" at the beginning of this report and "Risk Factors" in Item 1.A for additional discussion of some of these factors and risks.

General and Business Overview

We are an independent oil and gas company engaged in the acquisition, development and production of oil and natural gas, primarily in West Virginia, North Dakota, Texas and Louisiana. We are presently active in three of the most prolific shale resource plays in the United States, namely the Marcellus Shale, Eagle Ford Shale and Williston Basin/Bakken Shale. The Company is a Delaware corporation and was incorporated in 1997. In 2005, Magnum Hunter began oil and gas operations under the name Petro Resources Corporation. In May 2009, Magnum Hunter restructured its management team and refocused its business strategy, and in July 2009 changed its name to Magnum Hunter Resources Corporation.

The Company's new management implemented a business strategy consisting of exploiting the Company's inventory of lower risk drilling locations and the acquisition of undeveloped leases and long-lived proved reserves with significant exploitation and development opportunities primarily located in unconventional resource plays. As a result of this strategy, the Company has substantially increased its assets and production base through a combination of acquisitions and ongoing development drilling efforts, the Company's percentage of operated properties has increased significantly, its inventory of acreage and drilling locations in resource plays has grown and its management team has been expanded. Recently, management has focused on further developing and exploiting unconventional resource plays, the acquisition of additional operated properties and the development of associated midstream opportunities directly related to these regions.

2010 Recap and 2011 Outlook

Acquisition of Triad Energy Assets. On February 12, 2010, the Company closed the acquisition of substantially all of the assets of privately-held Triad Energy Corporation and certain of its affiliates, which we refer to collectively as Triad Energy, a 23-year old Appalachian Basin focused oil and gas production company. The Company acquired the assets of Triad Energy in connection with Triad Energy's reorganization under Chapter 11 of the United States Bankruptcy Code for consideration totaling approximately $81 million. The acquired assets are located in West Virginia, Ohio and Kentucky, in the Appalachian Basin. The acquired assets included (i) conventional, mature oil fields under primary and secondary development containing approximately 5.1 mmboe of proved reserves at December 31, 2009 (65% oil); (ii) over 2,000 producing wells (99% of which are operated by the Company's subsidiary, Triad Hunter, LLC); (iii) over 88,417 net acres, including over 47,000 net acres in the Marcellus Shale; (iv) approximately 182 miles of natural gas pipeline and/or rights-of-way; (v) three drilling rigs and service equipment; and (vi) two commercial salt water disposal facilities. These assets are now held by our wholly-owned subsidiaries Triad Hunter, LLC, Alpha Hunter Drilling, LLC, Eureka Hunter Pipeline, LLC, Hunter Disposal, LLC and Hunter Real Estate, LLC. Consideration for the assets acquired from Triad Energy totaled $81.6 million, consisting of:

- $8 million in cash ($4 million net);
- $15 million of our Series B Redeemable Convertible Preferred Stock, issued to certain banks who were secured creditors of Triad Energy in its Chapter 11 proceedings (In June 2010, all outstanding shares of Series B Preferred Stock were either converted into shares of common stock of the Company or redeemed by the Company for cash);

- $55 million repayment of Triad Energy senior debt through borrowings under our senior credit facility discussed below; and

- Assumption of approximately $3 million of equipment indebtedness.

Completed PostRock Acquisition. On December 24, 2010, the Company's subsidiary, Triad Hunter, LLC, which we refer to as Triad Hunter, entered into a definitive agreement to acquire certain Marcellus Shale oil and gas properties and leasehold mineral interests located in Wetzel and Lewis Counties, West Virginia from affiliates of PostRock Energy Corporation.

On December 30, 2010, Triad Hunter closed on the first phase of the transaction for the acquisition of certain Marcellus Shale assets located in Wetzel County for a total purchase price of $28 million. The purchase price consisted of (i) $14 million in cash and (ii) approximately 2.25 million newly issued restricted common shares of Magnum Hunter. On January 14, 2011, Triad Hunter closed on the second phase of the transaction for the acquisition of certain Marcellus Shale assets located in Lewis County for a total purchase price of $11.75 million. The purchase price consisted of (i) $5.875 million in cash and (ii) 946,314 newly issued restricted common shares of Magnum Hunter.

The third phase of the transaction is contemplated to close in the future for Magnum Hunter to acquire the third and smallest package of assets, subject to the determination by Magnum Hunter that certain events and conditions precedent to the closing have occurred or been satisfied.

Triad Hunter operates 100% of the properties acquired in the first two phases of the transaction. These properties include a total of approximately 9,423 gross acres (6,758 net acres), comprised of approximately 4,451 gross acres (2,225 net acres) in Wetzel County and approximately 4,972 gross acres (4,533 net acres) in Lewis County. The acquired acreage is located in the general proximity of Triad Hunter's existing Marcellus Shale acreage located in Tyler, Pleasants and Doddridge Counties, West Virginia. The majority of future lease expirations across the acquired acreage can be extended through a manageable drilling program which is planned for early 2011. The Company's proved reserves at December 31, 2010 included approximately 11.64 bcfe associated with the properties acquired in the first phase of the transaction.

Pending NGAS Resources Acquisition. On December 23, 2010, the Company entered into an arrangement agreement with NGAS Resources, Inc., a British Columbia corporation, which we refer to as NGAS, pursuant to which the Company will acquire all of the issued and outstanding equity of NGAS. NGAS is an independent exploration and production company focused on unconventional natural gas plays in the eastern United States, principally in the southern Appalachian Basin (the Huron and Weir Shales in Kentucky).

The proposed acquisition will be implemented pursuant to a court-approved plan of arrangement under British Columbia law. Under the plan of arrangement, each common share of NGAS will be transferred to the Company for the right to receive 0.0846 shares of the Company's common stock. Upon closing of the transaction, Magnum Hunter will issue approximately 6.6 million common shares to the NGAS shareholders, representing (i) approximately 5% of Magnum Hunter's fully diluted common shares outstanding as of February 14, 2011 (such percentage assuming completion of both the NGAS acquisition and the pending NuLoch Resources Inc. acquisition described below) or (ii) approximately 7% of Magnum Hunter's fully diluted common shares outstanding as of February 14, 2011 (such percentage assuming completion of the NGAS acquisition but not the pending NuLoch Resources Inc. acquisition). Certain NGAS liabilities will be refinanced under a new senior credit facility to be provided to the Company by BMO Capital Markets. In connection with the pending NuLoch Resources Inc. acquisition, the Company received a commitment for the new senior credit facility, which will have an initial borrowing base of $145 million, assuming completion of both acquisitions.

The NGAS assets to be acquired by the Company include proved reserves of 78.4 bcfe as of December 31, 2009 (74% natural gas and 65% proved developed producing), long-lived reserves with an R/P ratio of 23.4 years, daily production of approximately 9.2 mmcfe as of September 30, 2010 and approximately 330,000 gross lease acres (68% undeveloped) in Kentucky. (As of February 15, 2011, information with respect to NGAS's proved reserves as of December 31, 2010 was not yet available.)

The NGAS acquisition requires approval of NGAS' shareholders, and is subject to customary closing conditions. The NGAS acquisition is scheduled to close on or about March 31, 2011, although there is no assurance that the acquisition will ultimately be consummated.

Pending NuLoch Resources Acquisition. On January 19, 2011, the Company entered into an arrangement agreement among the Company, MHR ExchangeCo Corporation, a newly-formed corporation existing under the laws of the Province of Alberta and an indirect wholly owned subsidiary of the Company, which we refer to as ExchangeCo, and NuLoch Resources Inc., a corporation existing under the laws of the Province of Alberta, which we refer to as NuLoch, pursuant to which the Company through ExchangeCo will acquire all of the issued and outstanding equity of NuLoch. NuLoch is a Canadian public oil and natural gas producer with headquarters in Calgary, Alberta.

The proposed acquisition will be implemented pursuant to a court-approved plan of arrangement under Alberta law. The arrangement will involve an exchange of NuLoch's common shares to the Company for shares of the Company's common stock and/or exchangeable shares of ExchangeCo, as described below. Pursuant to the plan of arrangement, holders of NuLoch shares who are residents of Canada will receive, at the holder's election, (i) a number of exchangeable shares equal to the number of NuLoch shares exchanged multiplied by the exchange ratio of 0.3304, (ii) a number of Magnum Hunter common shares equal to the number of NuLoch shares exchanged multiplied by the exchange ratio, or (iii) a combination of exchangeable shares and Magnum Hunter common shares as described in clauses (i) and (ii) above. Holders of NuLoch shares who are non-Canadian residents will receive a number of Magnum Hunter common shares equal to the number of NuLoch shares exchanged multiplied by the exchange ratio. The exchangeable shares will be exchangeable into Magnum Hunter common shares (on a share-for-share basis) and will carry voting and dividend/distribution rights which are designed to put holders of the exchangeable shares in the same functional and economic position as holders of Magnum Hunter common shares. Any exchangeable shares not previously exchanged will be automatically exchanged for Magnum Hunter common shares on the one year anniversary of the closing date of the proposed transaction, unless the Company exchanges them earlier upon the occurrence of certain events.

In connection with the proposed transaction, Magnum Hunter will issue approximately 42.8 million common shares (including Magnum Hunter common shares issuable upon exchange of the exchangeable shares of ExchangeCo) to the NuLoch security holders, representing (i) approximately 32% of Magnum Hunter's fully diluted common shares outstanding as of February 14, 2011 (such percentage assuming completion of both the NuLoch and NGAS acquisitions) or (ii) approximately 34% of Magnum Hunter's fully diluted common shares outstanding as of February 14, 2011 (such percentage assuming completion of the NuLoch acquisition but not the NGAS acquisition). As of December 31, 2010, NuLoch had no outstanding long-term debt.

The NuLoch acquisition requires approval of NuLoch's shareholders and optionholders, and the issuance of Magnum Hunter common stock in connection with the acquisition requires approval of Magnum Hunter's stockholders. The NuLoch acquisition is also subject to customary closing conditions. The NuLoch acquisition is scheduled to close no later than May 31, 2011, although there is no assurance that the acquisition will ultimately be consummated.

Divestiture of West Texas /Cinco Terry Assets. On October 29, 2010, we sold our 10% non-operated interest in the Cinco Terry property located in Crockett County, Texas, to the operator of the property, for $21.5 million in cash before closing adjustments. The effective date of the transaction was October 1, 2010. The net proceeds of the sale were used to pay down outstanding debt under our credit agreement.

Senior Credit Facility. On February 12, 2010, we amended and restated our credit agreement to provide for a borrowing base of $70 million, increased from $25 million to allow for the acquisition of the Triad Energy assets.

On May 13, 2010, we entered into an amendment of the credit agreement. The amendment increased our borrowing base from $70 million to $75 million. The amendment also released Eureka Hunter Pipeline, LLC, referred to as Eureka Hunter, as a guarantor and pledgor under the credit agreement.

On November 30, 2010, we entered into a second amendment to the credit agreement, referred to as the second amendment. The second amendment established the tranche A portion of the Company's borrowing base at $65 million (due to the sale of our Cinco Terry properties) and established the tranche B portion of the borrowing base at $6.5 million. This reflected an increase in the Company's total borrowing base from $65 million to $71.5 million.

The second amendment also designated Eureka Hunter and any future subsidiaries of Eureka Hunter as restricted subsidiaries for purposes of the credit agreement, and amended certain negative covenants of the credit agreement to reflect such subsidiaries' designation as restricted subsidiaries. The second amendment continues to permit the Company to make certain investments in Eureka Hunter.

Pursuant to the second amendment, the lenders made a tranche B term loan to the Company in the amount of $6.5 million associated with the Eureka Hunter pipeline. The tranche B loan bears interest, which is payable not less frequently than quarterly, at the rate of 5.50% per annum and is due and payable in full on the final maturity date of November 30, 2011, referred to as the tranche B maturity date, subject to required prepayments as a result of reductions in the tranche B borrowing base as set forth below. Prior to the tranche B maturity date, any increase in the tranche A portion of the Company's borrowing base as a result of a redetermination of the borrowing base that results in the tranche A portion exceeding $65 million will automatically and permanently reduce the amount of the tranche B portion of the borrowing base by the amount of such increase in the Tranche A portion on a dollar for dollar basis. Also, prior to the tranche B maturity date, the tranche B portion of the borrowing base will be automatically and permanently reduced by a specified percentage of any net cash proceeds from the sale of certain capital assets, or from the issuance, incurrence or assumption of certain debt for borrowed money, relating to the Company's Eureka Hunter pipeline. The tranche B portion of the borrowing base is principally intended to be utilized to fund the Company's development of the Eureka Hunter pipeline.

In connection with the pending NuLoch acquisition, Magnum Hunter has received a commitment for a new $250 million amended and restated senior credit facility with an initial borrowing base of $145 million to be provided by BMO Capital Markets, secured by the Company's existing asset base, including the assets being acquired from NuLoch and NGAS.

Redemption of Series B Preferred Stock. On June 8, 2010, the Company redeemed 3,000,000 shares of its Series B Redeemable Convertible Preferred Stock, referred to as the Series B Preferred Stock, for the aggregate amount of $11.3 million. We had the right to redeem all outstanding shares of the Series B Preferred Stock if Magnum Hunter's common shares average trading price equaled or exceeded $4.74 per share for five consecutive trading days. Our common share average trading price per share met this criteria as of May 14, 2010.

In connection with the redemption, a holder of the Series B preferred stock converted 1,000,000 shares of Series B Preferred Stock into shares of our restricted common stock. As a result, all outstanding shares of the Series B Preferred Stock have been retired.

Equity Financings. We raised substantial cash through equity transactions in 2010. Those transactions included:

- $38.7 million of common equity financings throughout the course of the year.
- $64.9 million in gross proceeds from the issuance of our 10.25% Series C Cumulative Perpetual Preferred Stock, at a price of $25.00 per share. We incurred costs of $1.4 million to issue those shares.
- $16.1 million in gross proceeds from the exercise of warrants and stock options during 2010.

Shale Resource Play Properties

Appalachian Basin/Marcellus Shale. In the Appalachian Basin, we currently operate approximately 2,090 wells (primarily conventionally completed), and we own approximately 91,870 net acres, including approximately 56,595 net acres overlying the Marcellus Shale, as well as the shallow sandstones. Approximately 75% of our leases are held by production. Our currently producing wells are 64% oil wells, and 99% of the wells are operated by the Company. We plan to expand our Marcellus Shale development program in 2011. We have budgeted $59.9 million for the drilling of 15 gross (12.5 net) horizontal wells.

South Texas/Eagle Ford Shale. At February 1, 2011 we had approximately 48,000 gross acres (approximately 23,000 net) primarily targeting the Eagle Ford Shale in South Texas. We have budgeted $65.1 million in capital expenditures for 2011 associated with leasing new acreage and the drilling of 14 gross (7 net) horizontal wells.

Williston Basin/Bakken Shale. We own an approximately 43% average, non-operated working interest in 15 fields located in the Williston Basin in North Dakota comprising 151 wells and approximately 15,000 gross (6,540 net) acres. Approximately 90% of these leases, which are located in Burke, Renville, Ward, Bottineau, and McHenry Counties, North Dakota, are held by production. We exited 2010 producing approximately 392 bbls per day equivalent from these properties.

Other Properties

South Louisiana/East Chalkley — Our East Chalkley field is located in Cameron Parish, Louisiana. The unit consists of approximately 714 gross acres. This developmental project is an exploitation of bypassed oil reserves remaining in a natural gas field located at depths between 9,300 and 9,400 feet. At December 31, 2010, proved reserves on an SEC basis were 274 mboe, consisting of 88% oil and 47% proved developed. Our proved reserves on a NYMEX strip basis were 277 mboe. The Company operates East Chalkley and owns an approximately 62% working interest and a 42.7% net revenue interest. We have not allocated any capital exploration budget for this project in 2011 and are actively seeking to divest this non-core asset.

East Texas/Surprise — The Surprise Project is located in Nacogdoches County, Texas with natural gas potential from multiple horizons including James Lime, Pettit, Travis Peak, Expanded Bossier, Cotton Valley, and Haynesville Shale formations. The prospect area consists of approximately 4,796 gross (479 net) acres, and we have a 10% working interest and a 7.4% net revenue interest in the prospect. We currently do not have any capital allocated to this project or area for 2011.

Other — In addition to our unconventional and other conventional properties, we have approximately 157,758 gross (13,371 net) undeveloped acres in New Mexico, Kentucky and Utah. We do not currently plan to allocate any of our capital expenditure budget to these areas for 2011.

Eureka Hunter Midstream

The acquisition of assets from Triad Energy included important infrastructure assets for the effective development of the Company's Marcellus Shale unconventional resources. With increased drilling activity in the region, relying on third party oilfield service providers and pipeline operators can be costly. Access to a pipeline system is vital to flow natural gas to sales and often is a deciding factor in drilling and production decisions. The summary below provides a brief overview of the midstream services we operate and control. We anticipate these assets will generate an attractive revenue stream as we actively market them to third party producers in the Appalachian Basin.

The Eureka Hunter pipeline consists of approximately 182 miles of pipeline, gathering systems and/or rights-of-way located in northern West Virginia, in the Marcellus Shale. The rights-of-way run through Pleasants, Tyler, Ritchie, Wetzel, Marion, Harrison, Doddridge, Lewis and Monongalia Counties. We are currently constructing a new 20 inch high-pressure pipeline with up to 200 mmcfpd of throughput capacity. The first pipeline section of six miles was turned to sales on December 22, 2010. The next section of the pipeline of approximately 10 miles, which together with the initial six mile section comprising the first phase, is expected to be completed by June 30, 2011. We expect to have sufficient capacity to gather significant quantities of Company-produced natural gas from our Marcellus Shale development program, as well as third-party gas. We have budgeted $25 million to this project for 2011 which will be used for the construction of approximately six miles of main line and 12 miles of laterals.

In December 2010, the Company entered into an agreement for the construction of a new 200 mmcf per day capacity cryogenic natural gas processing plant. The processing plant will process natural gas and natural gas liquids gathered on the Eureka Hunter pipeline. Installation and hookup of the plant will begin upon delivery of the plant, scheduled for October 2011. The plant is expected to be operational by mid-year 2012. With the Company's first section of the Eureka Hunter pipeline system operational, the purchase of the plant furthers the Company's goal of becoming a fully integrated producer, gas gatherer and processor in this region. The plant will allow us to not only gather and process our equity natural gas, but also to provide a conduit for other producers in the area. We anticipate funding capital requirements for the plant through a combination of a partnership with an industry participant and/or project financing. Our pending acquisition of NGAS contemplates the restructuring of an existing out-of-market gas gathering and transportation agreement between NGAS and a third party, and as part of the restructuring such third party would be granted a limited option to acquire a 50% ownership interest in the processing plant. We are also discussing funding arrangements for the plant with other potential industry partners.

Equipment and Services

Alpha Hunter Drilling — As part of the acquisition of the Triad Energy assets, we acquired oilfield service equipment which is operated by our subsidiary, Alpha Hunter Drilling, LLC. This equipment consists primarily of three drilling rigs, a workover rig and heavy machinery, which are used in our operations and also those of third parties. We anticipate using our rigs to drill the vertical portions of our Marcellus Shale wells and then switching to larger rigs for the horizontal sections. This flexibility is expected to reduce the overall drilling costs, as well as improve the timing of drilling activity. As of February 14, 2011, two of our drilling rigs were under multi-well drilling contracts to large producers in the area. The third drilling rig will be utilized for drilling the top hole for our 2011 Marcellus Shale drilling program and will be leased to third party operators on the spot market.

Hunter Disposal — Typically, Marcellus Shale wells produce significant amounts of water that, in most cases, require disposal. Producers often remove the water in trucks for proper disposal in approved facilities. While this method has been the only option to many producers in the Appalachian Basin, it adds a significant operating burden and increases costs. Our subsidiary, Hunter Disposal LLC, owns and operates a salt water disposal facility located in Ohio, with current capacity of approximately 120,000 barrels of water per month. Additionally, Hunter Disposal owns and operates a second commercial salt water disposal facility located in the Primrose Field in Lee County, Kentucky. This disposal facility averages 45,000 bbls of water per month. This facility has a capacity for increased disposal up to 60,000 barrels of water per month with minimal capital requirements. In addition to utilizing our disposal facilities to reduce our operating costs and more importantly provide a cost-efficient option to dispose of water generated from our Marcellus Shale drilling program, we market our disposal capabilities to third party operators.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting policies generally accepted in the United States. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Actual results may differ from the estimates and assumptions used in the preparation of our consolidated financial statements. Described below are the most significant policies we apply in preparing our consolidated financial statements, some of which are subject to alternative treatments under U.S. GAAP. We also describe the most significant estimates and assumptions we make in applying these policies. See Note 2 — Summary of Significant Accounting Policies to our consolidated financial statements.

Oil and Gas Activities — Successful Efforts

Accounting for oil and gas activities is subject to special, unique rules. We use the successful efforts method of accounting for our oil and gas activities. The significant principles for this method are:

- geological and geophysical evaluation costs are expensed as incurred;
- dry holes for exploratory wells are expensed, and dry holes for developmental wells are capitalized; and
- capitalized costs related to proved oil and gas properties, including wells and related equipment and facilities, are evaluated for impairment based on an analysis of undiscounted future net cash flows in accordance with ASC 360, Accounting for the Impairment or Disposal of Long Lived Assets. If

undiscounted cash flows are insufficient to recover the net capitalized costs related to proved properties, then we recognize an impairment charge in income from operations equal to the difference between the net capitalized costs related to proved properties and their estimated fair values based on the present value of the related future net cash flows.

Proved Reserves

On December 31, 2008, the SEC released a Final Rule, *Modernization of Oil and Gas Reporting*, approving revisions designed to modernize oil and gas reserve reporting requirements. The new reserve rules first became effective for our financial statements for the year ended December 31, 2009 and our 2009 year-end proved reserve estimates. The most significant revisions to the reporting requirements include:

- *Commodity prices.* Economic producibility of reserves is now based on the unweighted, arithmetic average of the closing price on the first day of the month for the 12-month period prior to fiscal year end, unless prices are defined by contractual arrangements;

- *Undeveloped oil and gas reserves.* Reserves may be classified as "proved undeveloped" for undrilled areas beyond one offsetting drilling unit from a producing well if there is reasonable certainty that the quantities will be recovered;

- *Reliable technology.* The rules now permit the use of new technologies to establish the reasonable certainty of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes;

- *Unproved reserves.* Probable and possible reserves may be disclosed separately on a voluntary basis;

- *Preparation of reserves estimates.* Disclosure is required regarding the internal controls used to assure objectivity in the reserves estimation process and the qualifications of the technical person primarily responsible for preparing reserves estimates; and

- *Third party reports.* We are now required to file with the SEC the report of any third party used to prepare or audit our reserve estimates.

In addition, in January 2010, FASB issued Accounting Standards Update, or the Update, 2010-03, "Oil and Gas Reserve Estimation and Disclosures," to provide consistency with the new reserve rules. The Update amends existing standards to align the reserves estimation and disclosure requirements under GAAP with the requirements in the SEC's reserve rules. We adopted the new standards effective December 31, 2009. The new standards are applied prospectively as a change in estimate.

For the year ended December 31, 2010, we engaged Cawley, Gillespie & Associates, Inc, independent petroleum engineers, to prepare independent estimates of the extent and value of the proved reserves associated with certain of our oil and gas properties in accordance with guidelines established by the SEC, including the recent revisions designed to modernize oil and gas reserve reporting requirements. We adopted these revisions effective December 31, 2009.

Estimates of proved oil and gas reserves directly impact financial accounting estimates including depletion, depreciation and amortization expense, evaluation of impairment of properties and the calculation of plugging and abandonment liabilities. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The data for any reservoir may change substantially over time due to results from operational activity. Proved reserve volumes at December 31, 2010, were estimated based on the unweighted, arithmetic average of the closing price on the first day of each month for the 12-month period prior to December 31, 2010 for oil and natural gas in accordance with the new reserve rules. The average price used for oil was $79.43 and for natural gas was $4.37.

See also Items 1. — "Business" and 2. "Properties — Proved Reserves" and Note 12 — Other Information to our consolidated financial statements for additional information regarding our estimated proved reserves.

Derivative Instruments and Commodity Derivative Activities

Unrealized gains and losses, at fair value, are included on our consolidated balance sheets as current or non-current assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of our commodity derivative contracts are recorded in earnings as they occur and included in other income (expense) on our consolidated statements of operations. We estimate the fair values of swap contracts based on the present value of the difference in exchange-quoted forward price curves and contractual settlement prices multiplied by notional quantities. We internally valued the collar contracts using industry-standard option pricing models and observable market inputs. We use our internal valuations to determine the fair values of the contracts that are reflected on our consolidated balance sheets. Realized gains and losses are also included in "Gain (loss) on derivative contracts" on our consolidated statements of operations.

We are exposed to credit losses in the event of nonperformance by the counterparties on our commodity derivatives positions and have considered the exposure in our internal valuations. However, we do not anticipate nonperformance by the counterparties over the term of the commodity derivatives positions.

Changes in the derivative's fair value are currently recognized in the statement of operations unless specific commodity derivative hedge accounting criteria are met and such strategies are designated. For qualifying cash-flow commodity derivatives, the gain or loss on the derivative is deferred in accumulated other comprehensive (loss) income to the extent the commodity derivative is effective. The ineffective portion of the commodity derivative is recognized immediately in the statement of operations. Gains and losses on commodity derivative instruments included in accumulated other comprehensive (loss) income are reclassified to oil and gas sales revenue in the period that the related production is delivered. Derivative contracts that do not qualify for commodity derivative accounting treatment are recorded as derivative assets and liabilities at fair value in the balance sheet, and the associated unrealized gains and losses are recorded as current income or expense in the statement of operations.

Historically, we have not designated our derivative instruments as cash-flow hedges. We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record changes in such fair value in earnings on our consolidated statements of operations under the caption entitled "Gain (loss) on derivative contracts."

Although we have not designated our derivative instruments as cash-flow hedges, we use those instruments to reduce our exposure to fluctuations in commodity prices related to our oil and gas production. We record both realized and unrealized gains and losses under those instruments in other revenues on our consolidated statements of operations. We recorded (i) a realized gain from the settlement of derivative contracts of $3.9 million for the year ended December 31, 2010, (ii) a realized gain from the settlement of derivative contracts of $5.4 million for the year ended December 31, 2009 and (iii) a realized loss from the settlement of derivative contracts of $1.8 million for the year ended December 31, 2008. Realized gains and losses result from actual cash settlements received or paid under the derivative contracts. For the year ended December 31, 2010, we recognized an unrealized loss of $3.1 million from the change in the fair value of commodity derivatives. For the year ended December 31, 2009, we recognized an unrealized loss of $7.7 million from the change in the fair value of commodity derivatives. For the year ended December 31, 2008, we recognized an unrealized gain of $9.1 million from the change in the fair value of commodity derivatives. Unrealized gains and losses result from changes in the fair market value of the derivative contracts from period to period, and represent non-cash gains or losses. Changes in commodity prices could have a significant effect on the fair value of our derivative contracts. A hypothetical 10% increase in the NYMEX floating prices would have resulted in a $2.2 million decrease in the December 31, 2010 fair value recorded on our balance sheet, and a corresponding increase to the loss on commodity derivatives in our statement of operations. See Note 2 — "Summary of Significant Accounting Policies," Note 3 — "Fair Value of Financial Instruments," and Note 4 — "Financial Instruments and Derivatives" to our consolidated financial statements for additional information on our derivative instruments.

Asset Retirement Obligation

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives, in accordance with applicable federal, state and local laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value as of the asset's inception, with an offsetting increase to proved properties. Periodic accretion of discount of the estimated liability is recorded as accretion expense in the consolidated statements of operations.

Our liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of wells and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Our liability for asset retirement obligations was approximately $4.5 million and $2.0 million at December 31, 2010 and 2009, respectively. See Note 7 — "Asset Retirement Obligations" to our consolidated financial statements for more information.

Share-Based Compensation

Our Stock Incentive Plan allows grants of stock, options, and other stock-based awards to employees and outside directors. Grants of awards may increase our general and administrative expenses subject to the size and timing of the grants. For the years ended December 31, 2010, 2009, and 2008, we recognized approximately $6.4 million, $3.1 million, and $1.6 million in non-cash stock compensation, respectively. See Note 9 — "Share Based Compensation" to our consolidated financial statements for additional information.

Valuation of Property and Equipment

The Company accounts for the impairment and disposition of long-lived assets in accordance with ASC 360, *Accounting for the Impairment or Disposal of Long-Lived Assets*. ASC 360 requires that the Company's long-lived assets, including its oil and gas properties, be assessed for potential impairment in their carrying values whenever events or changes in circumstances indicate such impairment may have occurred. An impairment charge to current operations is recognized when the estimated undiscounted future net cash flows of the asset are less than its carrying value. Any such impairment is recognized based on the differences in the carrying value and estimated fair value of the impaired asset.

The guidance provides for future revenue from the Company's oil and gas production to be estimated based upon prices at which management reasonably estimates such products will be sold. These estimates of future product prices may differ from current market prices of oil and gas. Any downward revisions to management's estimates of future production or product prices could result in an impairment of the Company's oil and gas properties in subsequent periods.

The long-lived assets of the Company which are subject to evaluation consist primarily of oil and gas properties. Due to the regularly scheduled impairment reviews by management, the Company recognized a non-cash, pre-tax charge against earnings of approximately $0.3 million, $0.6 million, and $2.0 million for the years ended December 31, 2010, 2009, and 2008, respectively. See Note 2 — "Summary of Significant Accounting Policies" to our consolidated financial statements for additional information.

Revenue Recognition

Revenues associated with sales of crude oil, natural gas, natural gas liquids and petroleum products, and other items are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery of goods occurs, either immediately or within a fixed delivery schedule that is reasonable and customary in the industry.

Revenues from the production of natural gas and crude oil properties in which we have an interest with other producers are recognized based on the actual volumes we sold during the period. Any differences between volumes sold and entitlement volumes, based on our net working interest, which are deemed to be non-recoverable through remaining production, are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are generally not significant.

Revenues from field servicing activities are recognized at the time the services are provided and earned as provided in the various contract agreements. Gas gathering revenues are recognized at the time the natural gas is delivered at the destination point.

Income Taxes

We account for income taxes under the liability method. Deferred tax assets and liabilities are determined based on differences between financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. We measure and record income tax contingency accruals in accordance with ASC 740, *Income Taxes*.

We recognize liabilities for uncertain income tax positions based on a two-step process. The first step is to evaluate the tax position for recognition by determining if the weight of available evidence indicates that it is more likely than not that the position will be sustained on audit, including resolution of related appeals or litigation processes, if any. The second step requires us to estimate and measure the tax benefit as the largest amount that is more than 50% likely to be realized upon ultimate settlement. It is inherently difficult and subjective to estimate such amounts, as we must determine the probability of various possible outcomes. We reevaluate these uncertain tax positions on a quarterly basis or when new information becomes available to management. These reevaluations are based on factors including, but not limited to, changes in facts or circumstances, changes in tax law, successfully settled issues under audit, expirations due to statutes, and new audit activity. Such a change in recognition or measurement could result in the recognition of a tax benefit or an increase to the tax accrual.

We classify interest related to income tax liabilities as income tax expense, and if applicable, penalties are recognized as a component of income tax expense. The income tax liabilities and accrued interest and penalties that are anticipated to be due within one year of the balance sheet date are presented as current liabilities in our consolidated balance sheets. See Note 11 — "Income Taxes" to our consolidated financial statements for additional information.

Recently Issued Accounting Pronouncements

In January 2010, the FASB issued ASC 2010-06, Improving Disclosures about Fair Value Measurements (ASC 820-10). These new disclosures require entities to separately disclose amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and the reasons for the transfers. In addition, in the reconciliation for fair value measurements for Level 3, entities should present separate information about purchases, sales, issuances, and settlements. This guidance is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances and settlements in the roll forward of activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010 and for interim periods within those fiscal years. Our adoption of the disclosures, excluding the Level 3 activity disclosures, did not have a material impact on our notes to the condensed consolidated financial statements. See Note 3 — Fair Value of Financial Instruments for additional information. We are still evaluating the impact of the Level 3 disclosure requirements on our notes to the consolidated financial statements.

In February 2010, the FASB issued ASC 2010-09, Amendments to Certain Recognition and Disclosure Requirements, related to subsequent events under ASC 855, Subsequent Events. This guidance states that if an entity is and SEC filer, it is required to evaluate subsequent events for disclosure through the date that the financial statements are issued. We adopted this guidance as of February 2010 and have included the required disclosures in our condensed consolidated financial statements. See Note 16 — Subsequent Events for additional information.

Effects of Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2010, 2009, and 2008. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment. It may also increase the cost of labor or supplies. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher prices.

Results of Operations

The following table sets forth summary information regarding natural gas, oil and NGL revenues, production, average product prices and average production costs and expenses for the last three fiscal years. Gas is converted at the rate of one bbl equals six mcf.

	Years Ended December 31,		
	2010	2009	2008
Revenues (in thousands)			
Oil	$22,892	$6,138	$ 9,624
Gas	4,823	469	569
Total oil and gas sales	$27,715	$6,607	$10,193
Field operations revenue	$ 4,742	$ —	$ —
Field operations expense	$ 4,363	$ —	$ —
Production			
Oil (mbbls)	316	115	111
Gas (mmcf)	952	191	130
Total (mboe)	475	146	132
Total (boe/d)	1,301	401	363
Average prices			
Oil (per bbl)	$ 72.41	$53.56	$ 86.92
Gas (per mcf)	5.07	2.46	4.36
Total average price (per boe)	$ 58.37	$45.11	$ 76.96
Costs and expenses (per boe)			
Lease operating	$ 21.90	$26.48	$ 30.42
Severance tax and marketing	4.85	3.41	5.36
Exploration	1.97	5.40	55.45
Impairment of properties	0.64	4.33	14.90
General and administrative (see Note)	52.44	57.98	29.93
Depletion, depreciation and accretion	18.79	21.63	53.04

Note: General and administrative includes acquisition related expenses of $4.69 per boe in 2010, $7.08 per boe in 2009, and none in 2008 and non-cash stock compensation of $13.32 per boe in 2010, $21.11 per boe in 2009, and $11.75 per boe in 2008.

Years ended December 31, 2010 and 2009

Oil and gas production. Production increased by 329 mboe to 475 mboe for the year ended December 31, 2010 from 146 mboe for the year ended December 31, 2009, or 225%. Production for 2010 on a boe basis was 67% oil and 33% natural gas compared to 78% oil and 22% natural gas for 2009. The change in the percent of oil and gas produced was due to the acquisition of Triad Energy's assets in February 2010. Our average daily production on a boe basis was 1,301 boe per day during 2010 compared to 401 boe per day for the 2009 year representing an overall increase of 900 boe per day (giving effect to the Company's sale in October 2010 of its Cinco Terry property as if such sale occurred at the beginning of each such period). The increase in production in 2010 compared to 2009 is primarily attributable to the acquisition of the Triad Energy assets which closed in February 2010 and continuing exploration and development efforts in other fields. Triad accounted for 285 mboe of the increase in production in

2010. Other fields where production increased were Eagleville (Eagle Ford Shale) with a 15 mboe increase, South Caesar with a 12 mboe increase, South Texas with a 9 mboe increase, East Chalkley with a 6 mboe increase, and Williston with a 8 mboe increase. The Eagleville and South Caesar increases were due to success in our exploratory drilling program. The increases in South Texas and East Chalkley were to acquisition of property interests. The increase in Williston production was due to increased response from our unitization and secondary recovery program and drilling program. We experienced a 6 mboe decrease in production at our Surprise field due to natural decline.

Oil and gas sales. Oil and gas sales increased $21.1 million, or 319%, for the year ended December 31, 2010 to $27.7 million from $6.6 million for the year ended December 31, 2009. The increase in oil and gas sales principally resulted from increases in our oil and natural gas production due to increased acquisition activity and exploratory drilling efforts throughout the year. The average price we received for our production increased from $45.11 per boe to $58.37 per boe, a 29% increase. Of the $21.1 million increase in revenues, approximately $8.4 million was attributable to an increase in oil and gas prices and $12.7 million was attributable to the 329 mboe increase in production volumes from in 2010. The prices we receive for our products are generally tied to commodity index prices. We periodically enter into commodity derivative contracts in an attempt to offset some of the variability in prices. (See the discussion of commodity derivative activities below.)

Field Operations Revenue and Expense. Field operations revenue was $4.7 million and field operations expense was $4.4 million for the year ended December 31, 2010. The increases in both field revenue and field expense in 2010 were due to the acquisition of the Triad Energy assets and include revenue and expenses from services provided to third parties for drilling, well servicing, natural gas transportation, salt water disposal and operating services.

Other income. Other income for the year ended December 31, 2010 was $0.3 million, all resulting from Triad's sale of used pipe. Other income for the year ended December 31, 2009 included $0.2 million in a liquidated damage penalty assessed against an operating partner.

Lease operating expense. Our lease operating expenses ("LOE") increased $6.5 million, or 168%, for the year ended December 31, 2010 to $10.4 million from $3.9 million for the year ended December 31, 2009. However, LOE per boe decreased from $26.48 in 2009 to $21.90 in 2010. The increase in total LOE is attributable to increased volume produced, which accounted for an increase in cost of $8.7 million, reduced by lower cost per boe produced, which offset the volume effect by $2.2 million. The decrease in the per boe cost is due to the impact of the lower cost per boe produced of the Triad Energy assets acquired in 2010.

Severance taxes and marketing. Our severance taxes and marketing increased by $1.8 million, or 361%, for the year ended December 31, 2010 to $2.3 million from $499,000 for the year ended December 31, 2009. The increase in production taxes and marketing was due to the increase in oil and gas sales as explained above.

Exploration. We recorded $936,000 of exploration expense for the year ended December 31, 2010, compared to $791,000 for the year ended December 31, 2009. We experienced higher geological and geophysical costs in 2010 as a result of the acquisition of Triad Energy's assets. The 2009 period included exploratory dry hole expense of $538,000 versus none in 2010.

Impairment of oil and gas properties. We review for impairment our long-lived assets to be held and used, including proved and unproved oil and gas properties accounted for under the successful efforts method of accounting. As a result of this review of the recoverability of the carrying value of our assets, we recorded an impairment of oil and gas properties of $306,000 and $634,000 in 2010 and 2009, respectively. The 2010 impairment was primarily due to a write-down of our investment in the Giddings Field based on reserve report economics. The 2009 impairment resulted from a writedown of $634,000 of unproved acreage costs in the Boomerang and LeBlanc Prospect areas, which we do not expect to drill.

Depletion, depreciation and accretion. Our depletion, depreciation and accretion expense, or DD&A, increased $5.8 million, or 182%, to $8.9 million for the year ended December 31, 2010 from $3.2 million for the year ended December 31, 2009 due to increased production in 2010. Our DD&A per boe decreased by $2.84, or 13.1%, to $18.79 per boe for the year ended December 31, 2010, compared to $21.63 per boe for the year ended December 31, 2009. The decrease in DD&A per boe was primarily attributable to the increase in proved developed producing reserves and total proved reserves at a lower average investment cost per unit at December 31, 2010 compared to December 31, 2009.

General and administrative. Our general and administrative expenses ("G&A"), increased $16.4 million, or 193%, to $24.9 million ($52.44 per boe) for the year ended December 31, 2010 from $8.5 million ($57.98 per boe) for the year ended December 31, 2009. Our G&A increased in 2010 primarily as a result of the Triad Energy assets acquisition and a higher level of corporate activity. Our G&A for 2010 included higher share-based compensation, as well as higher salaries and related employee benefit costs attributable to an increase in employees from the prior year period, higher rent and office costs, and consulting and professional services, all due to the increased level of activity which began in the first quarter of 2010 and is continuing. Non-cash G&A expenses totaled $6.3 million and $3.1 million for the 2010 and 2009 periods, respectively, and represent noncash stock compensation granted to our employees. Our G&A expenses also increased in 2010 due to acquisition related expenses, specifically the Triad Energy asset acquisition, which closed on February 12, 2010, as well as other acquisitions and divestitures commenced and completed during the year. These costs were expensed due to the requirements of ASC 805 which states that acquisition costs must be expensed rather than capitalized as part of the cost of the asset being acquired for years beginning in 2009. Acquisition related expenses were $2.2 million in 2010 versus $1.0 million in 2009.

Interest expense, net. Our interest expense, net of interest income, increased $843,000, or 34%, to $3.5 million for the year ended December 31, 2010 from $2.7 million for the year ended December 31, 2009. This increase was substantially the result of our higher average debt level during 2010 and the amortization of deferred finance costs related to the closing of our new senior credit facility.

Commodity derivative activities. Realized gains and losses from our commodity derivative activity increased our earnings by $3.9 million and $5.4 million for the years ended December 31, 2010 and 2009, respectively. Realized gains and losses are derived from the relative movement of oil and gas prices on the products we sell in relation to the range of prices in our derivative contracts for the respective years. The unrealized loss on commodity derivatives was $3.1 million for 2010 and $7.7 million for 2009. As commodity prices increase, the fair value of the open portion of those positions decreases, and vice versa. As commodity prices decrease, the fair value of the open portion of those positions increases. Historically, we have not designated our derivative instruments as cash-flow hedges. We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record all changes in realized and unrealized gains and losses on our consolidated statements of operations under the caption entitled "Gain (loss) on derivative contracts". Our gain or loss from realized and unrealized derivative contracts was a gain of $814,000 and a loss of $2.3 million for the years ended December 31, 2010 and 2009, respectively.

Net loss attributable to non-controlling interest. Net income attributable to non-controlling interest was $129,000 in 2010 versus net loss of $63,000 in 2009. This represents 12.5% of the net income or loss incurred by our subsidiary, PRC Williston. We record a non-controlling interest in the results of operations of this subsidiary because we are contractually obligated to make distributions to the holders of this interest whenever we make distributions to ourselves from the subsidiary company.

Loss from Continuing Operations. We had a loss from continuing operations of $22.3 million in 2010 versus a loss of $15.6 million in 2009, an increase of $6.7 million in loss, or 43%. This was due to an increase in operating loss of $8.8 million, principally due to higher G&A expense and higher interest expense offset by a decline in loss derivatives of $3.1 million.

Income from discontinued operations. On October 29, 2010, we closed on a divestiture of our Cinco Terry property effective October 1, 2010. As a result of this divestiture, we recognized income from discontinued operations of $8.5 million in 2010, consisting of a gain on sale of $6.6 million and reclassification of $1.9 million of operating income less interest expense associated with the property to discontinued operations. We also reclassified $445,000 of Cinco Terry operating income less interest expense to discontinued operations for 2009. As a result of this divestiture, our average daily production volume of 313 boepd and 302 boepd from this property for the years ended December 31, 2010 and 2009, respectively, have been excluded from our reported total average daily production volumes for these periods.

Dividends on Preferred Stock. Dividends on our Series B and Series C Preferred Stock were $2.5 million in 2010 versus $26,000 in 2009. The Series C Preferred Stock has a stated value of $70.2 million and $5.4 million at December 31, 2010 and 2009, respectively, and carries a cumulative dividend rate of 10.25% per annum. We commenced the issuance of Series C Preferred Stock in December 2009. We redeemed all outstanding Series B Preferred Stock in June 2010.

Net loss attributable to common shareholders. Net loss attributable to common shareholders was $16.3 million in 2010 versus $15.1 million in 2009. Our net loss per common share, basic and diluted was $0.25 per share in 2010 compared to $0.39 per share in 2009. Our weighted average shares outstanding increased by 24,967,691, or 64.1%, from 2009 to 2010, and was partially responsible in the decline of our net loss per share between the periods. Our net loss per share from continuing operations was $0.38 in 2010 versus $0.40 in 2009. The $6.7 million increase in loss from continuing operations was offset by the increase in weighted average shares outstanding. We had income per share from discontinued operations of $0.13 in 2010 versus $0.01 in 2009, primarily due to the gain on sale of Cinco Terry.

Years ended December 31, 2009 and 2008

Oil and gas production. Production increased by 14 mboe to 146 mboe for the year ended December 31, 2009 from 132 mboe for the year ended December 31, 2008, or 11%. Production for 2009 on a boe basis was 78% oil and 22% natural gas compared to 84% oil and 16% natural gas for 2008. Our average daily production on a boe basis was 401 boe per day during 2009 compared to 363 boe per day for the 2008 year representing an overall increase of 38 boe per day. The increase in production in 2009 compared to 2008 is primarily attributable to exploratory drilling in our Gulf Coast area and the acquisition of Sharon Hunter Resources, which accounted for increased production of 18 mboe and 2 mboe, respectively. We had a production decline of 6 mboe at Williston due to natural decline prior to the effects of our unitization and secondary recovery program being realized.

Oil and gas sales. Oil and gas sales decreased $3.6 million, or 35%, for the year ended December 31, 2009 to $6.6 million from $10.2 million for the year ended December 31, 2008. The decrease in oil and gas sales principally resulted from a decline in price received for oil and natural gas. The average price we received for our production decreased from $76.96 per boe to $45.11 per boe, a 41% decrease. Of the $3.6 million decrease in revenues, approximately $4.2 million was attributable to a decrease in oil and gas prices, offset by an increase in revenue of $602,000 attributable to the increase in production volumes from 132 mboe in 2008 to 146 mboe in 2009. The prices we receive for our products are generally tied to commodity index prices. We periodically enter into commodity derivative contracts in an attempt to offset some of the variability in prices. See the discussion of commodity derivative activities below.

Other income. Other income for the year ended December 31, 2009 was $222,000, primarily from a liquidated damages penalty assessed against an operating partner. Other income for the year ended December 31, 2008 was $1.4 million and included a liquidated damages penalty of $200,000 and a gain on sale of $1.2 million.

Lease operating expense. Our lease operating expenses, decreased $150,000, or 4%, for the year ended December 31, 2009 to $3.9 million ($26.48 per boe) from $4.0 million ($30.42 per boe) for the year ended December 31, 2008. The decrease in the per boe cost is due to the decrease experienced in our Williston field. We expect this trend to continue in our North Dakota fields where fixed costs are a relatively high percentage of total LOE and where we have seen response to our unitization and secondary recovery efforts adding additional production.

Severance taxes and marketing. Our severance taxes and marketing decreased by $210,000, or 30%, for the year ended December 31, 2009 to $499,000 from $710,000 for the year ended December 31, 2008. The decrease in production taxes was a function of the decrease in oil and gas revenues between 2009 and 2008 as explained above.

Exploration. We recorded $791,000 of exploration expense for the year ended December 31, 2009, compared to $7.3 million for the year ended December 31, 2008. Exploration expense in the 2008 period resulted primarily from dry hole costs in our North Dakota fields and the write-off of costs in our South San Arroyo and Whitewater prospects.

Impairment of oil and gas properties. We review for impairment our long-lived assets to be held and used, including proved and unproved oil and gas properties accounted for under the successful efforts method of accounting. As a result of this review of the recoverability of the carrying value of our assets, we recorded an impairment of oil and gas properties of $634,000 and $2.0 million in 2009 and 2008, respectively. The 2009 impairment resulted from a write-off of unproved acreage costs in the Boomerang and LeBlanc Prospect areas, while the impairment in 2008 was due to a lower revenue valuation at one of our Williston Basin fields.

Depletion, depreciation and accretion. Our depletion, depreciation and accretion expense, decreased $3.9 million, or 55%, to $3.2 million for the year ended December 31, 2009 from $7.0 million for the year ended December 31, 2008. Our DD&A per boe decreased by $31.41, or 59%, to $21.63 per boe for the year ended December 31, 2009, compared to $53.04 per boe for the year ended December 31, 2008. The decrease in DD&A per boe was primarily attributable to the increase in proved developed producing reserves and total proved reserves at December 31, 2009 compared to December 31, 2008.

General and administrative. Our general and administrative expenses, increased $4.5 million, or 114%, to $8.5 million ($57.98 per boe) for the year ended December 31, 2009 from $4.0 million ($29.93 per boe) for the year ended December 31, 2008. Our G&A increased in 2009 primarily due to level of activity in 2009. Our G&A for 2009 included higher share-based compensation, as well as higher salaries, related employee benefit costs attributable to an increase in staff from the prior year period, higher rent and office costs, and consulting and professional services, all due to the increased activity in 2009. Non-cash G&A expenses totaled $3.1 million and $1.6 million for the 2009 and 2008 periods, respectively, and represent noncash stock compensation granted our employees. We also incurred acquisition related expenditures, primarily related to the Triad acquisition of $1.0 million in 2009 versus none in 2008.

Interest expense, net. Our interest expense, net of interest income, increased $518,000 to $2.7 million for the year ended December 31, 2009 from $2.2 million for the year ended December 31, 2008. This increase was substantially the result of our higher average debt level during 2009 and the amortization of deferred finance costs related to the closing of our new senior revolving credit facility in 2009.

Loss on debt extinguishment. We incurred a loss of $2.8 million on debt extinguishment in 2008 versus non in 2009. The 2008 loss was due to the payoff of a credit facility with a different previous lender.

Commodity derivative activities. Realized gains and losses from commodity derivative activity increased our earnings by $5.4 million and $1.8 million for the years ended December 31, 2009 and 2008, respectively. Realized gains and losses are derived from the relative movement of oil and gas prices on the products we sell in relation to the range of prices in our derivative contracts for the respective years. We incurred an unrealized loss on commodity derivatives of $7.7 million for 2009 and an unrealized gain on commodity derivatives of $9.1 million for 2008. As commodity prices increase, the fair value of the open portion of those positions decreases, and vice versa. As commodity prices decrease, the fair value of the open portion of those positions increases. Historically, we have not designated our derivative instruments as cash-flow hedges. We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record all changes in realized and unrealized gains and losses on our consolidated statements of operations under the caption entitled "Gain (loss) on derivative contracts". Our gain or loss from realized and unrealized derivative contracts was a loss of $2.3 million and a gain of $7.3 million for the years ended December 31, 2009 and 2008, respectively.

Net loss attributable to non-controlling interest. Net loss attributable to non-controlling interest was $63,000 in 2009 versus net loss of $1.6 million in 2008. This represents 12.5% of the net income or loss incurred by our subsidiary, PRC Williston. We record a non-controlling interest in the results of operations of this subsidiary because we are contractually obligated to make distributions to the holders of this interest whenever we make distributions to ourselves from the subsidiary company.

Loss from continuing operations. Our loss from continuing operations was $15.6 million in 2009 versus a loss of $9.5 million in 2008, an increase of $6.1 million, or 64%. Components of this increase were an increase in operating income of $2.8 million and a decrease in debt extinguishment loss of $2.8 million offset by higher net interest expense of $518,000, an increase in loss on derivative contracts of $9.6 million and a decrease in income from non-controlling interest of $1.6 million.

Income from discontinued operations. As a result of the divestiture of our Cinco Terry property on October 29, 2010, we reclassified operating income less applicable interest expense to income from discontinued operations of $445,000 in 2009 and $2.6 million in 2008. As a result of this divestiture, our average daily production volumes of 302 boepd and 209 boepd from this property for the years ended December 31, 2009 and 2008, respectively, have been excluded from our reported total average daily production volumes for these periods.

Dividends on Preferred Stock. Dividends on our and Series C Preferred Stock were $26,000 in 2009 versus $0 in 2008. The Series C Preferred Stock has a stated value of $5.4 million at December 31, 2009 and $0 for December 31, 2008, and carries a cumulative dividend rate of 10.25% per annum. Dividends on our series A preferred stock were none in 2009 and $734,000 in 2008. The series A preferred stock was redeemed in September 2008.

Net loss attributable to common shareholders. Net loss attributable to common shareholders was $15.1 million in 2009 versus $7.6 million in 2008 due to the reasons stated above. Our net loss per common share, basic and diluted was $0.39 per share in 2009 compared to $0.21 per share in 2008. Our weighted average shares outstanding increased by 2.2 million shares in 2009 from 2008. We had loss from continuing operations per share of $0.28 in 2008, and earnings from discontinued operations per share of $0.01 in 2009 versus $0.07 in 2008 due to the divestiture of Cinco Terry.

Liquidity and Capital Resources

We generally rely on cash generated from operations, borrowings under our revolving credit facility and, to the extent that credit and capital market conditions will allow, future public and private equity and debt offerings to satisfy our liquidity needs. Our ability to fund planned capital expenditures and to make acquisitions depends upon our future operating performance, availability of borrowings under our revolving credit facility, and more broadly, the availability of equity and debt financing, which is affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control. We cannot predict whether additional liquidity from equity or debt financings beyond our revolving credit facility will be available or acceptable on our terms, or at all, in the foreseeable future.

Our cash flow from operations is driven by commodity prices and production volumes and the effect of commodity derivatives. Prices for oil and natural gas are affected by national and international economic and political environments, national and global supply and demand for hydrocarbons, seasonal influences of weather and other factors beyond our control. Our working capital is significantly influenced by changes in commodity prices, and significant declines in prices will cause a decrease in our production volumes and exploration and development expenditures. Cash flows from operations are primarily used to fund exploration and development of our oil and gas properties.

We intend to fund 2011 capital expenditures, excluding any acquisitions, primarily out of internally-generated cash flows and, as necessary, borrowings under our revolving credit facility. We may also raise additional funds in the public debt and equity markets. As of December 31, 2010, we had $35.0 million available to borrow under our revolving credit facility.

For the year ended December 31, 2010, our primary sources of cash were from financing activities, proceeds from asset sales, and cash on hand at the beginning of the year. Approximately $117.6 million of cash from sale of common and preferred stock and the proceeds from exercises of warrants, along with our $101.6 million of borrowings under our revolving credit facility, $21.2 million of proceeds from sale of assets, and $2.3 million of cash on hand were used to fund our acquisitions and drilling program, repay debt under our revolving credit facility, redeem our Series B preferred stock, and pay deferred financing costs on our amended and restated credit facility.

For the year ended December 31, 2009, our primary sources of cash were from financing and operating activities and cash on hand at the beginning of the year. Approximately $19.1 million of cash from sale of common and preferred stock, $3.4 million of cash from operating activities and $6.1 million of cash on hand were used to fund our acquisitions and drilling program, repay debt under our revolving credit facility, and purchase new derivative contracts.

For the year ended December 31, 2008, our primary sources of cash were proceeds from borrowings under our revolving credit facility of $9.4 million, proceeds from asset sales of $7.8 million, operating cash flows of $3.4 million and cash on hand at the beginning of the year of $15.4 million. Cash was used to fund capital expenditures of $16.2 million, invest in a partnership for $2.0 million, repay our revolving credit line for $2.3 million, pay deferred financing costs of $1.5 million and redeem preferred stock for $8.0 million.

In comparing 2010 and 2009, our cash flows from operations decreased in 2010 to ($1.2) million from $3.4 million in 2009 due to the increase in general and administrative costs partially offset by realized gains on derivative contracts and lower exploratory costs. Cash provided by operating activities was unchanged in 2009 at approximately $3.4 million.

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

	Years Ended December 31,		
	2010	2009	2008
		(In thousands)	
Cash flows provided by (used in) operating activities	$ (1,167)	$ 3,372	$ 3,437
Cash flows used in investing activities	(118,280)	(16,624)	(10,378)
Cash flows provided by (used in) financing activities	117,720	9,413	(2,338)
Net decrease in cash and cash equivalents	$ (1,727)	$ (3,839)	$ (9,279)

We define liquidity as funds available under our revolving credit facility plus year-end cash and cash equivalents. At December 31, 2010, we had $30.0 million in debt outstanding under our revolving credit facility, compared to $13.0 million in debt outstanding under the revolving credit facility at December 31, 2009. The following table summarizes our liquidity position at December 31, 2010 compared to December 31, 2009:

	Years Ended December 31,	
	2010	2009
	(In thousands)	
Borrowing base	$ 71,500	$ 25,000
Cash and cash equivalents	554	2,282
Debt	(30,000)	(13,000)
Liquidity	$ 42,054	$ 14,282

There are several factors that will affect our liquidity in 2011. We expect to have increased operating cash flows as a result of the pending NGAS and NuLoch acquisitions and the successful results of our 2010 drilling program. We also expect to have increased salary and other administrative costs associated with the increased number of employees resulting from the new acquisitions. We will be required to repay any borrowing on Tranche B of our senior credit facility no later than November 30, 2011. At December 31, 2010, the amount outstanding under tranche B was $6.5 million.

Operating Activities

For the year ended December 31, 2010, our cash flow used by operating activities was $1.2 million compared to cash provided by operating activities of $3.4 million in 2009, a decrease in cash provided of $4.6 million. The increase in field operations expense caused $4.4 million of the decline, and non-controlling interest expense increased by approximately $200,000. Our cash flow used by operating activities for the year ended 2010 included net income of $8.5 million from discontinued operations which includes the gain on sale of discontinued operations of $6.7 million and will not have a material impact on future cash flows from operating activities.

Investing Activities

We had $81.8 million in capital expenditures in 2010 versus $13.3 million in 2009 and $16.2 million in 2008. Other uses of funds for investing activities in 2010 were $59.5 million to acquire the Triad Energy assets. Other sources of funds from investing activities in 2010 were net proceeds from the sale of our interests in the Cinco Terry property for $21.2 million net of adjustments and the use of $1.8 million in previous drilling advances to other operators. Other uses of funds for investing activities in 2009 were $2.7 million to purchase a net derivative position upon closeout of our previous credit facility and the unwinding of most of our previous derivatives, and we advanced $1.3 million to other operators as cash call advances on pending capital expenditures. Other sources of funds from investing activities in 2009 were proceeds from the sale of a portion of our increased interests in the East Chalkley field for $0.5 million and cash we received in the Sharon Resources, Inc. acquisition of $0.2 million. In 2008, we realized funds from sale of assets of $7.8 million and used funds for a partnership investment of $2.0 million.

Financing Activities

We borrowed $101.6 million under our revolving credit facility in 2010 compared to $25.7 million in 2009 and $9.4 million in 2008. We repaid $84.9 million, $34.2 million, and $2.3 million of amounts outstanding under our revolving credit facility for the years ended December 31, 2010, 2009, and 2008, respectively. In 2010 we received $38.7 million in net proceeds from the sale of approximately 10.8 million shares of our common stock, $63.4 million in net proceeds from the issuance of approximately 2.6 million shares of our Series C Preferred Stock and $16.1 million from the exercise of warrants. In 2010, we also paid dividends of $2.5 million, $11.3 million in cash upon redemption of Series B Preferred Stock, and $604,000 for shares loaned to the Company's stock ownership plan. In 2009, we also received $14.1 million in net proceeds from the sale of approximately 8.9 million shares of our common stock (some of which were issued along with approximately 1.7 million common stock warrants) and $5.0 million in net proceeds from the issuance of approximately 215,000 shares of our Series C Preferred Stock. In 2009 we also paid $114,000 on the contingent liability associated with our sale of the Hall-Houston Partnership and paid $1.0 million of deferred financing costs on our newly established revolving credit facility. In 2008 we paid $1.5 million in deferred financing costs and paid $8.0 million to redeem our Series A Preferred Stock.

We believe that cash flows from operations and borrowings under our revolving credit facility will finance substantially all of our capital needs through 2011. We may also use our revolving credit facility for possible acquisitions and temporary working capital needs. Further, we may decide to access the public or private equity or debt markets for potential acquisitions, working capital or other liquidity needs, if such financing is available on acceptable terms. In November 2010, we filed a shelf registration statement with the SEC registering up to $250 million of common stock, preferred stock, warrants and debt securities. The registration statement was declared effective by the SEC on November 12, 2010.

2011 Capital Expenditures Budget

The following table summarizes our estimated capital expenditures for 2011. We intend to fund 2011 capital expenditures, excluding any acquisitions, primarily out of internally-generated cash flows and, as necessary, borrowings under our revolving credit facility and public issuance of equity securities.

	Year Ending December 31, 2011
	(In thousands)
Appalachian Basin	
Marcellus Shale drilling	$ 56,300
Eureka Hunter Pipeline	25,000
Acreage acquisition	3,600
Eagle Ford	
Eagle Ford Shale drilling	61,500
Acreage acquisition	3,600
Total capital expenditures	$150,000

Our capital expenditures budget for 2011 is subject to change depending upon a number of factors, including economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the results of our development and exploration efforts, the availability of sufficient capital resources for drilling prospects, our financial results, the availability of leases on reasonable terms and our ability to obtain permits for the drilling locations.

Revolving Credit Facility

On November 23, 2009, the Company entered into a credit agreement with Bank of Montreal which provided for an asset-based, three-year senior secured revolving credit facility with an initial borrowing base availability of $25 million.

On February 12, 2010, the Company entered into an amended and restated credit agreement with Bank of Montreal and Capital One, N.A. This restated credit agreement amended and restated in its entirety the credit facility dated November 23, 2009. The restated credit agreement provides for an asset-based, senior secured revolving credit facility, referred to as the revolving facility, maturing November 23, 2012, and had an initial borrowing base of $70 million. The revolving facility is governed by a semi-annual borrowing base redetermination (on April 1 and November 1 of each year) derived from the Company's proved crude oil and natural gas reserves, and based on such redetermination, the borrowing base may be decreased or increased up to a maximum commitment level of $150 million. The initial $70 million borrowing base consisted of a $60 million A tranche and a $10 million B tranche.

On May 13, 2010, the Company's borrowing base under the revolving facility was increased from $70 million to $75 million. The tranche B facility was eliminated. The increase in the borrowing base reflected the increase in the Company's proved reserves at December 31, 2009 and the acquisition of the Triad Energy assets which closed in February 2010. Other new participating banks included UBS Loan Finance LLC, Amegy Bank National Association, and Key Bank National Association.

On November 30, 2010, the Company entered into a second amendment to the revolving facility, referred to as the second amendment. The second amendment reset the tranche A portion of the Company's borrowing base under the revolving facility at $65 million (due to the sale of the Company's Cinco Terry properties) and established the tranche B portion of the borrowing base at $6.5 million, subject to change (a) pursuant to any redetermination of the tranche A portion of the borrowing base in accordance with the provisions of the revolving facility and (b) as described in the paragraph below. This reflected an increase in the Company's total borrowing base from $65 million to $71.5 million. This new borrowing base reflected the increase in the Company's proved reserves at June 30, 2010 resulting from the Company's February 2010 acquisition of the Triad Energy assets out of bankruptcy, and as adjusted for the October 2010 divestiture of the Company's non-operated working interest in the Cinco Terry property in West Texas for total consideration of $21.3 million.

Pursuant to the second amendment, on November 30, 2010, the lenders made a tranche B term loan to the Company in the amount of $6.5 million associated with the Eureka Hunter pipeline. The tranche B loan bears interest, which is payable not less frequently than quarterly, at the rate of 5.50% per annum and is due and payable in full on November 30, 2011, referred to as the tranche B maturity date, subject to required prepayments as a result of reductions in the tranche B borrowing base as set forth below. Prior to the tranche B maturity date, any increase in the tranche A portion of the Company's borrowing base as a result of a redetermination of the borrowing base that results in the tranche A portion exceeding $65 million will automatically and permanently reduce the amount of the tranche B portion of the borrowing base by the amount of such increase in the tranche A portion on a dollar for dollar basis. Also, prior to the tranche B maturity date, the tranche B portion of the borrowing base will be automatically and permanently reduced by a specified percentage of any net cash proceeds from the sale of certain capital assets, or from the issuance, incurrence or assumption of certain debt for borrowed money, relating to the Company's Eureka Hunter pipeline. The tranche B portion of the borrowing base is principally intended to be utilized to fund the Company's development of the Eureka Hunter pipeline.

The second amendment also designated Eureka Hunter Pipeline, LLC, a subsidiary of the Company, and Eureka Hunter's directly-owned subsidiary, as restricted subsidiaries for purposes of the revolving facility, and amended certain negative covenants of the revolving facility to reflect such subsidiaries' designation as restricted subsidiaries. The second amendment continued to permit the Company to make certain investments in Eureka Hunter.

The revolving facility has a commitment fee which ranges between 0.50% and 0.75%, based upon the unused portion of the borrowing base. Borrowings under the revolving facility will, at the Company's election, bear interest at either (i) an alternate base rate ("ABR") equal to the higher of (A) BMO's base rate, (B) the Federal Funds Effective Rate, plus 0.5% per annum and (C) the LIBO Rate for a one month interest period on such day, plus 1.0% or (ii) the adjusted LIBO Rate, which is the rate stated on Reuters BBA Libor Rates C2BORO1 market for one, two, three, six or twelve months, as adjusted for statutory reserve requirements for Eurocurrency liabilities, plus, in each of the cases described in (i) or (ii) above, an applicable margin ranging from 1.50% to 2.50% for ABR loans and from 2.50% to 3.50% for adjusted LIBO Rate loans. In the event a default occurs and is continuing under the revolving facility, the lenders may increase the interest rate then in effect by an additional 2% per annum plus the rate then applicable to ABR loans. Subject to certain permitted liens, the Company's obligations under the revolving facility are secured by a grant of a first priority lien on no less than 80% of the value of the proved oil and gas properties of the Company and its subsidiaries, including 90% of the total value of the oil and gas properties of the Company and its subsidiaries that are categorized as proved reserves that are both developed and producing as such terms are defined in the Definitions for Oil and Gas Reserves as promulgated by the Society of Petroleum Engineers.

At December 31, 2010 and 2009, the Company had loans outstanding under this revolving facility of $30 million ($23.5 million in tranche A and $6.5 million in tranche B) and $13 million, respectively.

Covenants

The revolving credit facility, as amended, requires the Company to satisfy certain affirmative financial covenants, including maintaining (a) an interest coverage ratio (as such term is defined in the revolving credit facility) of not less than 2.5:1.0; (b) a ratio of total debt (as such term is defined in the revolving credit facility) to EBITDAX of not more than 4.0:1.0 for each fiscal quarter; and (c) a ratio of consolidated current assets (including available borrowing) to consolidated current liabilities of not less than 1.0:1.0. The Company is also required to enter into certain commodity price hedging agreements pursuant to the terms of the revolving credit facility. At December 31, 2010, we were in compliance with all of our covenants and had not committed any acts of default under the revolving credit facility.

The revolving credit facility also restricts certain payments, transactions with affiliates, incurrence of other debt, consolidations and mergers, assets sales, investments in other entities, liens on properties, and other customary restrictions for agreements of this type In addition, the facility contains customary events of default that would permit our lenders to accelerate the debt under our the facility if not cured within applicable grace periods, including, among others, payment defaults, defaults in the performance of affirmative or negative covenants, the inaccuracy of representations or warranties, bankruptcy or related defaults, defaults relating to judgments and the occurrence of a change in control (as such term is defined in the facility).

To date we have experienced no disruptions in our ability to access our revolving credit facility. However, our lenders have substantial ability to reduce our borrowing base on the basis of subjective factors, including the loan collateral value that each lender, in its discretion and using the methodology, assumptions and discount rates that such lender customarily uses in evaluating oil and gas properties, assigns to our properties.

Related Party Transactions

During 2010 and 2009, we rented an airplane for business use at various times from Pilatus Hunter, LLC, an entity 100% owned by our chairman of the board, Mr. Gary C. Evans. Airplane rental expenses totaled $450,000, $161,000, and $0 for the years ended December 31, 2010, 2009, and 2008, respectively.

During 2010 and 2009, we obtained accounting services and office space from GreenHunter Energy, Inc., an entity for which Mr. Evans is a director, officer and major shareholder and Ronald D. Ormand, our chief financial officer, is a director. Professional services expenses totaled $212,000, $30,000, and $0 for the year ended December 31, 2010, 2009 and 2008, respectively.

Contractual Commitments

Our contractual commitments consist of long-term debt, accrued interest on long-term debt, operating lease obligations, a drilling contract, asset retirement obligations, and employment agreements with senior officers.

Our long-term debt is composed of borrowings under our revolving credit facility and various notes payable for equipment assumed in the Triad Energy assets acquisition. Interest on debt is based on the rate applicable under our revolving credit facility and notes payable, which ranged from 0.00% to 6.34% at December 31, 2010. See Note 8 in our consolidated financial statements.

As of December 31, 2010, we rent various office spaces in Houston, Texas, of approximately 22,966 square feet at a cost of $37,925 per month for remaining terms ranging from fourteen to sixty-five months. Triad had various lease commitments for periods ranging from three to eighty-three months at December 31, 2010, and with monthly payments of approximately $25,685 as of that date.

On September 25, 2010 the Company entered into a twelve month drilling contract. Our maximum liability under the drilling contract, which would apply if we terminated the contract before the end of its term, is approximately $3.2 million at December 31, 2010.

We have outstanding employment agreements with five of our senior officers for terms ranging from one to three years. Our maximum commitment under the employment agreements, which would apply if the employees covered by these agreements were all terminated without cause, was approximately $1.2 million at December 31, 2010.

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives, in accordance with applicable federal, state and local laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value as of the asset's inception, with an offsetting increase to proved properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement.

The following table summarizes these commitments as of December 31, 2010 (in thousands):

Contractual Obligations	Total	2011	2012 - 2013	2014 - 2015	After 2015
Long-term debt(1)	$33,151	$ 7,132	$24,793	$1,226	$ —
Interest on long-term debt(2)	2,730	1,539	1,159	32	—
Operating lease obligations(3)	2,557	754	870	636	297
Asset retirement obligations(4)	4,455	100	695	274	3,386
Employment agreements with senior officers	1,179	1,179	—	—	—
Drilling contract commitment	3,197	3,197	—	—	—
Total	$47,269	$13,901	$27,517	$2,168	$3,683

(1) See Note 8 to our consolidated financial statements for a discussion of our revolving credit facility.

(2) Interest payments have been calculated by applying the interest rates ranging from 0.00% — 6.34% at December 31, 2010, to the outstanding long-term debt of $33.2 million at December 31, 2010.

(3) Operating lease obligations are for office space and equipment.

(4) See Note 6 to our consolidated financial statements for a discussion of our asset retirement obligations.

Off-Balance Sheet Arrangements

From time to time, we enter into off-balance sheet arrangements and transactions that can give rise to off-balance sheet obligations. As of December 31, 2010, the off-balance sheet arrangements and transactions that we have entered into include undrawn letters of credit and operating lease agreements. We do not believe that these arrangements are reasonably likely to materially affect our liquidity or availability of, or requirements for, capital resources.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Some of the information below contains forward-looking statements. The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and gas prices and other related factors. The disclosure is not meant to be a precise indicator of expected future losses, but rather an indicator of reasonable possible losses. This forward-looking information provides an indicator of how we view and manage our ongoing market risk exposures. Our market risk sensitive instruments were entered into for commodity derivative and investment purposes, not for trading purposes.

Proved Reserves

Estimates of proved oil and gas reserves directly impact financial accounting estimates including depletion, depreciation and amortization expense, evaluation of impairment of properties and the calculation of plugging and abandonment liabilities. Proved oil and gas reserves are those quantities of oil and gas which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The data for any reservoir may change substantially over time due to results from operational activity. Proved reserve volumes at December 31, 2010 were estimated based on the unweighted, arithmetic average of the closing price on the first day of each month for the 12-month period prior to December 31, 2010 for natural gas, oil, and NGLs, in accordance with new reserve rules.

Changes in commodity prices and operation costs may also affect the overall evaluation of reservoirs. A hypothetical 10% decline in our December 31, 2010 estimated proved reserves would have increased our depletion expense by approximately $1.1 million for the year ended December 31, 2010.

Commodity Price Risk

Given the current economic outlook, we expect commodity prices to remain volatile. Even modest decreases in commodity prices can materially affect our revenues and cash flow. In addition, if commodity prices remain suppressed for a significant amount of time, we could be required under successful efforts accounting rules to write down our oil and gas properties.

We enter into financial swaps and collars to reduce the risk of commodity price fluctuations. We do not designate such instruments as cash flow hedges. Accordingly, we record open commodity derivative positions on our consolidated balance sheets at fair value and recognize changes in such fair values as income (expense) on our consolidated statements as they occur.

At December 31, 2010, we have the following commodity derivative positions outstanding:

Commodity	Type	Volume/Month	Duration	Price	Fair Market Value
Oil.	Buy - CALL	4562	Jan 11 - Dec 11	82.25	$ 797,111
Oil.	Buy - PUT	4,800 bbls	Jan 11 - Dec 11	80.00	(425,732)
Oil.	Buy - PUT	4,600 bbls	Jan 12 - Dec 12	80.00	(291,803)
Oil.	Buy - PUT	1400	Jan 11 - Dec 11	75.00	28,869
Oil.	Buy - PUT	3042	Jan 11 - Dec 11	75.00	63,062
Oil.	Buy - PUT	1525	Jan 12 - Dec 12	75.00	90,392
Oil.	Buy - PUT	150 bbl per day	Jan 11 - Mar 11	60.00	49
Oil.	Buy - PUT	150 bbl per day	Jan 11 - Mar 11	52.00	2
Oil.	Buy - PUT	200 bbl per day	Jan 11 - Dec 11	75.00	126,124
Oil.	Collar	4,178 bbls	Jan 12 - Dec 12	80.00 -100.00	(131,921)
Oil.	Collar	5,000 bbls	June 10 - Dec 11	70.00 - 82.25	(725,170)
Oil.	Sell - CALL	4562	Jan 11 - Dec 11	90.00	(503,117)
Oil.	Sell - CALL	1400	Jan 11 - Dec 11	95.00	(109,174)
Oil.	Sell - CALL	3042	Jan 11 - Dec 11	97.20	(203,728)
Oil.	Sell - CALL	1525	Jan 12 - Dec 12	108.00	(114,902)
Oil.	Sell - CALL	200 bbl per day	Jan 11 - Dec 11	100.00	(333,332)
Oil.	Sell - PUT	4562	Jan 11 - Dec 11	52.00	(7,078)
Oil.	Sell - PUT	1400	Jan 11 - Dec 11	60.00	(6,497)
Oil.	Sell - PUT	3042	Jan 11 - Dec 11	60.00	(14,203)
Oil.	Sell - PUT	1525	Jan 12 - Dec 12	55.00	(20,624)
Oil.	Swap	435 bbls	Jan 11 - Dec 11	85.25	(44,299)
Oil.	Swap	2,250 bbls	Jan 11 - Dec 11	85.00	(89,085)
Natural Gas	Collar	12,500 mmbtu	Jan 11 - Dec 11	5.00 - 8.20	94,505
Natural Gas	Collar	4,165 mmbtu	Jan 11 - Dec 11	5.00 - 8.95	31,801
Natural Gas	Collar	10,000 mmbtu	Jan 12 - Dec 12	5.00 - 9.82	69,012
Natural Gas	Collar	47,600 mmbtu	Jan 11 - Dec 11	5.50 - 7.10	549,074
Natural Gas	Collar	47,300 mmbtu	Jan 12 - Dec 12	5.00 - 8.40	302,517
Natural Gas	Swap	3,400 mmbtu	Jan 11 - Dec 11	5.98	52,047
Natural Gas	Swap	3,000 mmbtu	Jan 12 - Dec 12	6.15	38,148
					$(777,952)

At December 31, 2010 and 2009, the fair value of our open derivative contracts was a net liability of approximately $778,000, and an asset of $2.3 million, respectively.

Bank of Montreal is currently the only counterparty to our commodity derivatives positions. We are exposed to credit losses in the event of nonperformance by the counterparty on our commodity derivative positions. However, we do not anticipate nonperformance by the counterparty over the terms of the commodity derivatives positions. Bank of Montreal is the administrative agent and a participant in our revolving credit facility, and the collateral for the outstanding borrowings under our revolving credit facility is used as collateral for our commodity derivatives.

Unrealized gains and losses, at fair value, are included on our consolidated balance sheets as current or non-current assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of our commodity derivative contracts are recorded in earnings as they occur and included in other income (expense) on our consolidated statements of operations. We estimate the fair values of swap contracts based on the present value of the difference in exchange-quoted forward price curves and contractual settlement prices multiplied by notional quantities. We internally valued the collar, call, and put contracts using industry-standard option pricing models and observable market inputs. We use our internal valuations to determine the fair values of the contracts that are reflected on our consolidated balance sheets. Realized gains and losses are also included in other income (expense) on our consolidated statements of operations.

Historically, we have not designated our derivative instruments as cash-flow hedges. We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record changes in such fair value in earnings on our consolidated statements of operations under the caption entitled "Gain (loss) on derivative contracts."

Although we have not designated our derivative instruments as cash-flow hedges, we use those instruments to reduce our exposure to fluctuations in commodity prices related to our oil and gas production. We record both realized and unrealized gains and losses under those instruments in other revenues on our consolidated statements of operations. We recorded (i) a realized gain from the settlement of derivative contracts of $3.9 million for the year ended December 31, 2010, (ii) a realized gain from the settlement of derivative contracts of $5.4 million for the year ended December 31, 2009, and (iii) a realized loss from the settlement of derivative contracts of $1.8 million for the year ended December 31, 2008. Realized gains and losses result from actual cash settlements received or paid under the derivative contracts. For the year ended December 31, 2010, we recognized an unrealized loss of $3.1 million from the change in the fair value of commodity derivatives. For the year ended December 31, 2009, we recognized an unrealized loss of $7.7 million from the change in the fair value of commodity derivatives. For the year ended December 31, 2008, we recognized an unrealized gain of $9.1 million from the change in the fair value of commodity derivatives. Unrealized gains and losses result from changes in the fair market value of the derivative contracts from period to period, and represent non-cash gains or losses. Changes in commodity prices could have a significant effect on the fair value of our derivative contracts. A hypothetical 10% increase in the NYMEX floating prices would have resulted in a $1.3 million decrease in the December 31, 2009 fair value recorded on our balance sheet, and a corresponding increase to the loss on commodity derivatives in our statement of operations. See Note 2 — "Summary of Significant Accounting Policies," Note 3 — "Fair Value of Financial Instruments," and Note 4 — "Financial Instruments and Derivatives" to our consolidated financial statements for additional information on our derivative instruments.

To estimate the fair value of our commodity derivatives positions, we use market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and attempt to use the best available information. We determine the fair value based upon the hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and lowest priority to unobservable inputs (Level 3 measurement). The three levels of fair value hierarchy are as follows:

- *Level 1* — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. At December 31, 2010, we had no Level 1 measurements.

- *Level 2* — Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Our derivatives, which consist primarily of commodity swaps and collars, are valued using commodity market data which is derived by combining raw inputs and quantitative models and processes to generate forward curves. Where observable inputs are available, directly or indirectly, for substantially the full term of the asset or liability, the instrument is categorized in Level 2. At December 31, 2010, all of our commodity derivatives were valued using Level 2 measurements.

- *Level 3* — Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. At December 31, 2010, our Level 3 measurements were used to calculate our asset retirement obligation and our impairment analysis of proved properties at December 31, 2010.

Item 8. ***FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA***

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders
Magnum Hunter Resources Corporation

We have audited the accompanying consolidated balance sheets of Magnum Hunter Resources Corporation and subsidiaries (collectively "the Company") as of December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the two years in the period ended December 31, 2010. Our audits also included the financial statement schedules of the Company listed in Item 15(a). These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2010 and 2009, and the results of its operations and cash flows for each of the two years in the period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedules, when considered in relation to the consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 18, 2011 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ HEIN & ASSOCIATES LLP

Dallas, Texas
February 18, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Magnum Hunter Resources Corporation

We have audited Magnum Hunter Resources Corporation and subsidiaries' (collectively, the "Company") internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Magnum Hunter Resources Corporation and subsidiaries as of December 31, 2010 and 2009, and the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the two years in the period ended December 31,2010 and our report dated February 18, 2011 expressed an unqualified opinion thereon.

/s/ HEIN & ASSOCIATES LLP

Dallas, Texas
February 18, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors
Magnum Hunter Resources Corporation
Houston, Texas

We have audited the accompanying consolidated balance sheet of Magnum Hunter Resources Corporation (the "Company") as of December 31, 2008, and the related consolidated statements of operations, shareholders' equity, and cash flows for the year then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Magnum Hunter Resources Corporation as of December 31, 2008, and the results of operations and cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America.

/s/ MaloneBailey, LLP
www.malonebailey.com

Houston, Texas
March 30, 2009

MAGNUM HUNTER RESOURCES CORPORATION

CONSOLIDATED BALANCE SHEETS

	December 31, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 554,186	$ 2,281,568
Accounts receivable	11,705,046	2,706,086
Derivative assets	—	1,261,534
Prepaids and other current assets	867,013	94,113
Assets held for sale — current	—	529,957
Total current assets	13,126,245	6,873,258
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, successful efforts accounting	189,911,500	46,229,171
Gas gathering and other equipment	42,689,125	180,878
Total property and equipment	232,600,625	46,410,049
OTHER ASSETS:		
Assets held for sale — long term	—	11,128,583
Derivative assets	—	1,092,152
Deferred financing costs, net of amortization of $1,236,664 and $35,831, respectively	2,678,244	1,012,756
Other assets	561,711	67,253
Total Assets	$248,966,825	$ 66,584,051
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Current portion of notes payable	$ 7,132,455	$ 44,157
Accounts payable	29,839,557	3,813,623
Accrued liabilities	3,914,136	885,622
Revenue payable	2,629,999	342,585
Dividend payable	—	25,654
Derivative liability	718,771	69,136
Liabilities associated with assets held for sale — current	—	1,038,598
Total current liabilities	44,234,918	6,219,375
Payable on sale of partnership	640,695	640,695
Notes payable, less current portion	26,018,615	13,000,000
Derivative payable	59,181	—
Asset retirement obligation	4,455,327	1,964,749
Liabilities associated with assets held for sale — long term	—	67,557
Total liabilities	75,408,736	21,892,376
COMMITMENTS AND CONTINGENCIES (Note 14)		
REDEEMABLE PREFERRED STOCK:		
Series C Cumulative Perpetual Preferred Stock, cumulative dividend rate 10.25% per annum, 4,000,000 authorized, 2,809,456 and 214,950 issued & outstanding as of December 31, 2010 and 2009, respectively, with liquidation preference of $25.00 per share	70,236,400	5,373,750
SHAREHOLDERS' EQUITY:		
Preferred stock, 6,000,000 shares authorized, none issued and outstanding	—	—
Common stock, $0.01 par value; 150,000,000 shares authorized, 74,863,135 and 50,591,610 shares issued and outstanding as of December 31, 2010 and 2009, respectively	748,631	505,916
Additional paid in capital	152,438,989	71,936,306
Accumulated deficit	(49,402,300)	(33,135,693)
Treasury Stock, previously deposit on Triad, at cost, 761,652 shares	(1,310,357)	(1,310,357)
Unearned common stock in KSOP, at cost	(603,613)	—
Total Magnum Hunter Resources Corporation shareholders' equity	101,871,350	37,996,172
Noncontrolling interest	1,450,339	1,321,753
Total Shareholders' Equity	103,321,689	39,317,925
Total Liabilities and Shareholders' Equity	$248,966,825	$ 66,584,051

The accompanying Notes to Consolidated Financial Statements are an integral part of these Statements.

MAGNUM HUNTER RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2010	2009	2008
REVENUE:			
Oil and gas sales	$ 27,714,542	$ 6,606,901	$ 10,192,818
Field operations	4,741,889	—	—
Gain on sale of assets	71,069	14,000	1,196,963
Other income	196,173	222,668	200,000
Total revenue	32,723,673	6,843,569	11,589,781
EXPENSES:			
Lease operating expenses	10,399,323	3,878,512	4,028,906
Severance taxes and marketing	2,304,570	499,523	710,308
Exploration	936,371	790,569	7,344,390
Field Operations	4,362,618	—	—
Impairment of oil & gas properties	305,786	633,953	1,973,015
Depreciation, depletion and accretion	8,923,202	3,167,839	7,025,525
General and administrative	24,900,996	8,490,364	3,964,664
Total expenses	52,132,866	17,460,760	25,046,808
OPERATING LOSS	(19,409,193)	(10,617,191)	(13,457,027)
OTHER INCOME (EXPENSE):			
Interest income	60,526	959	188,932
Interest expense	(3,593,524)	(2,691,097)	(2,361,152)
Loss on debt extinguishment	—	—	(2,790,829)
Gain (loss) on derivative contracts	814,037	(2,325,251)	7,311,255
Loss from continuing operations before non-controlling interest	(22,128,154)	(15,632,580)	(11,108,821)
Net (income) loss attributable to non-controlling interest	(128,586)	63,156	1,640,466
Net loss attributable to Magnum Hunter Resources Corporation from continuing operations	(22,256,740)	(15,569,424)	(9,468,355)
Income from discontinued operations	8,456,811	445,215	2,582,021
Net loss	(13,799,929)	(15,124,209)	(6,886,334)
Dividends on Preferred Stock	(2,466,679)	(25,654)	(734,406)
Net loss attributable to common shareholders	$(16,266,608)	$(15,149,863)	$ (7,620,740)
Weighted average number of common shares outstanding, basic and diluted	63,921,525	38,953,834	36,714,489
Net loss from continuing operations	$ (0.38)	$ (0.40)	$ (0.28)
Net income from discontinued operations	$ 0.13	$ 0.01	$ 0.07
Net loss per common share, basic and diluted	$ (0.25)	$ (0.39)	$ (0.21)

The accompanying Notes to Consolidated Financial Statements are an integral part of these Statements.

MAGNUM HUNTER RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Number of Shares of Common	Deposit on Triad	Common Stock	Additional Paid in Capital	Accumulated Deficit	Treasury Stock	Unearned Common Shares in KSOP	Noncontrolling Interest	Total Equity
BALANCE, January 1, 2008	36,599,372	$ —	$365,994	$ 49,723,515	$(10,365,090)	$ —	$ —	$ 3,025,375	$ 42,749,794
Dividends on Series A Convertible Preferred	—	—	—	—	(734,406)	—	—	—	(734,406)
Restricted stock issued to employees and directors	168,800	—	1,688	341,782	—	—	—	—	343,470
Stock compensation	—	—	—	1,246,205	—	—	—	—	1,246,205
Net loss	—	—	—	—	(6,886,334)	—	—	(1,640,466)	(8,526,800)
BALANCE, December 31, 2008	36,768,172	$ —	$367,682	$ 51,311,502	$(17,985,830)	$ —	$ —	$ 1,384,909	$ 35,078,263
Restricted stock issued to employees and directors	1,886,200	—	18,862	1,361,719	—	—	—	—	1,380,581
Stock compensation	—	—	—	1,710,753	—	—	—	—	1,710,753
Issued 2,294,474 shares for acquisition of Sharon Resources, Inc.	2,294,474	—	22,944	2,661,591	—	—	—	—	2,684,535
Cost of issuing 214,950 shares of Series C Preferred Stock	—	—	—	(418,205)	—	—	—	—	(418,205)
Issued 8,881,112 shares of Common Stock	8,881,112	—	88,811	14,006,206	—	—	—	—	14,095,017
Dividends on Series C Convertible Preferred	—	—	—	—	(25,654)	—	—	—	(25,654)
Cost of issuing 761,652 shares as deposit on Triad Acquisition	761,652	(1,310,357)	7,617	1,302,740	—	—	—	—	—
Net loss	—	—	—	—	(15,124,209)	—	—	(63,156)	(15,187,365)
BALANCE, December 31, 2009	50,591,610	$(1,310,357)	$505,916	$ 71,936,306	$(33,135,693)	$ —	$ —	$ 1,321,753	$ 39,317,925
Restricted stock issued to employees and directors	2,539,317	—	25,393	425,584	—	—	—	—	450,977
Stock compensation	—	—	—	5,929,435	—	—	—	—	5,929,435
Stock Options surrendered by holder for cash payment	—	—	—	(115,500)	—	—	—	—	(115,500)
Issued shares of common stock for payment of services	55,932		559	164,441	—	—	—	—	165,000
Cost of issuing 2,594,506 shares of Series C Preferred Stock	—	—	—	(1,418,969)	—	—	—	—	(1,418,969)
Issued shares of Common Stock for cash	10,832,076	—	108,321	38,569,998	—	—	—	—	38,678,319
Issued shares of Common Stock upon exercise of warrants	7,536,654	—	75,367	16,030,693	—	—	—	—	16,106,060
Issued shares of common stock upon stock option exercise	52,500	—	525	124,303	—	—	—	—	124,828
Issued shares of Common Stock upon redemption of Series B Convertible Preferred Stock	1,000,000	—	10,000	3,722,000	—	—	—	—	3,732,000
Dividends on Series B Convertible Preferred	—	—	—	—	(130,625)	—	—	—	(130,625)
Dividends on Series C Cumulative Perpetual Preferred	—	—	—	—	(2,336,054)	—	—	—	(2,336,054)
761,652 shares of common stock as deposit on Triad Acquisition returned to treasury	—	1,310,357	—	—	—	(1,310,357)	—	—	—
Loan of 153,300 shares to KSOP	—	—	—	—	—	—	(603,613)	—	(603,613)
Issued shares of common stock for acquisition of assets	2,255,046	—	22,550	17,070,698	—	—	—	—	17,093,248
Net loss	—	—	—	—	(13,799,928)	—	—	128,586	(13,671,342)
BALANCE, December 31, 2010	74,863,135	$ —	$748,631	$152,438,989	$(49,402,300)	$(1,310,357)	$(603,613)	$ 1,450,339	$103,321,689

The accompanying Notes to Consolidated Financial Statements are an integral part of these Statements.

MAGNUM HUNTER RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2010	2009	2008
Cash flows from operating activities			
Net loss	$ (13,799,928)	$(15,124,209)	$ (6,886,334)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Non-controlling interest	128,586	(63,156)	(1,640,466)
Depletion, depreciation, and accretion	10,345,698	4,499,611	7,682,293
Stock-based compensation	6,380,412	3,091,334	1,589,675
Impairment	305,785	633,953	1,973,015
Gain on asset retirement obligation	—	—	(16,837)
Exploratory costs	—	647,001	7,140,013
Gain on sale of assets	(6,730,680)	(14,000)	(1,196,963)
Loss on extinguishment of debt	—	—	2,790,829
Unrealized (gain) loss on derivative contracts	3,062,502	7,700,129	(9,116,145)
Amortization of deferred financing cost included in interest expense	1,200,833	1,233,611	1,737,458
Changes in operating assets and liabilities:			
Accounts receivable and accrued revenue	(2,949,213)	(1,908,945)	(114,366)
Prepaid expenses and other current assets	134,277	(16,313)	(49,887)
Accounts payable	8,865,622	1,571,108	(631,563)
Revenue payable	359,476	342,585	—
Accrued liabilities	(8,470,237)	779,030	176,607
Net cash provided by (used in) operating activities	(1,166,867)	3,371,739	3,437,329
Cash flows from investing activities			
Capital expenditures	(81,842,289)	(13,274,656)	(16,222,790)
Change in advances	1,764,852	(1,326,889)	—
Cash received in purchase of Sharon Resources, Inc.	—	235,023	—
Net cash paid in acquisition of Triad	(59,500,299)	—	—
Proceeds from sale of assets	21,238,322	500,000	7,843,962
Purchase of derivatives	—	(2,700,850)	—
Change in deposits	58,681	(56,246)	—
Investment in partnership	—	—	(1,999,800)
Net cash used in investing activities	(118,280,733)	(16,623,618)	(10,378,628)
Cash flows from financing activities			
Net proceeds from sale of common stock and warrants	38,678,319	14,095,017	—
Net proceeds from sale of preferred shares	63,443,681	4,955,545	—
Proceeds from exercise of warrants	16,106,060	—	—
Loan KSOP shares	(603,613)	—	—
Options exercised	124,828	—	—
Options surrendered for cash	(115,500)	—	—
Preferred stock dividend paid	(2,492,333)	—	—
Principal payments on debt	(84,885,648)	(34,193,566)	(2,253,861)
Proceeds from debt borrowings	101,580,745	25,718,196	9,354,295
Payment on payable on sale of partnership	—	(113,560)	—
Payment of deferred financing costs	(2,866,321)	(1,048,587)	(1,471,545)
Redemption of preferred stock	(11,250,000)	—	(7,966,735)
Net cash provided by (used in) financing activities	117,720,218	9,413,045	(2,337,846)
Net decrease in cash and cash equivalents	(1,727,382)	(3,838,834)	(9,279,145)
Cash and cash equivalents, beginning of year	2,281,568	6,120,402	15,399,547
Cash and cash equivalents, end of year	$ 554,186	$ 2,281,568	$ 6,120,402
Cash paid for interest	$ 2,748,945	$ 2,142,454	$ 1,554,484
Noncash transactions			
Stock issued for acquisition of PostRock assets	$ 17,093,248	$ —	$ —
Series B Preferred stock issued for acquisition of Triad	$ 14,982,000	$ —	$ —
Debt assumed in acquisition of Triad	$ 3,411,816	$ —	$ —
Common stock issued for payment of services	$ 165,000	$ —	$ —
Common stock issued in conversion of Series C Perpetual Preferred Stock	$ 3,732,000	$ —	$ —
Capitalized interest in oil and gas properties	$ —	$ —	$ 1,080,177
Accrued capital expenditures	$ 23,217,800	$ —	$ 1,527,440
Stock issued for acquisition of Sharon Resources, Inc.	$ —	$ 2,684,535	$ —
Refinancing of Petrobridge loan	$ —	$ —	$ 16,239,152

The accompanying Notes to Consolidated Financial Statements are an integral part of these Statements.

NOTE 1 — ORGANIZATION AND NATURE OF OPERATIONS

Magnum Hunter Resources Corporation and subsidiaries ("Magnum Hunter") (a Delaware Corporation) is a Houston, Texas based independent exploration and production company engaged in the acquisition and development of producing properties, secondary enhanced oil recovery projects, and production of oil and natural gas in the United States.

On July 14, 2009, the Company formed a new subsidiary to purchase Magnum Hunter Resources, LP and the new subsidiary was merged into Petro Resources Corporation in order to effect a name change from "Petro Resources Corporation" to "Magnum Hunter Resources Corporation".

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation and Presentation

The consolidated financial statements include the accounts of Magnum Hunter and our wholly-owned subsidiaries, Sharon Hunter Resources, Inc. ("Sharon"), Triad Hunter, LLC, Alpha Hunter Drilling, LLC, Hunter Disposal, LLC, Eureka Hunter Pipeline, LLC, Hunter Real Estate, LLC, MHR Acquisition Company I, LLC, MHR Acquisition II, LLC, and MHR Acquisition Company III, LLC. We also have consolidated our 87.5% controlling interest in PRC Williston, LLC ("PRC") with noncontrolling interests recorded for the outside interest in PRC. All significant intercompany balances and transactions have been eliminated.

Our financial statements are prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of our financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. These estimates are based on information that is currently available to us and on various other assumptions that we believe to be reasonable under the circumstances. Actual results could differ from those estimates under different assumptions and conditions. Significant estimates are required for proved oil and gas reserves which, as described in Note 2 — Estimates of Proved Oil and Gas Reserves, may have a material impact on the carrying value of oil and gas property.

Critical accounting policies are defined as those significant accounting policies that are most critical to an understanding of a company's financial condition and results of operation. We consider an accounting estimate or judgment to be critical if (i) it requires assumptions to be made that were uncertain at the time the estimate was made, and (ii) changes in the estimate or different estimates that could have been selected could have a material impact on our results of operations or financial condition.

Reclassification of Prior-Year Balances

Certain prior-year balances in the consolidated financial statements have been reclassified to correspond with current-year classifications.

Cash and cash equivalents

Cash and cash equivalents include cash in banks and highly liquid debt securities that have original maturities of three months or less. At December 31, 2010, the Company had cash deposits in excess of FDIC insured limits at various financial institutions.

Financial Instruments

The carrying amounts of financial instruments including cash and cash equivalents, accounts receivable, notes receivable, accounts payable and accrued liabilities and long-term debt approximate fair value, as of December 31, 2010 and 2009. See Note 3 for commodity derivative fair value disclosures.

Oil and Gas Properties

Capitalized Costs

Our oil and gas properties comprised the following:

	December 31, 2010	December 31, 2009
Mineral interests in properties:		
Unproved properties	$ 57,427,823	$ 12,490,361
Proved properties	84,967,556	28,119,550
Wells and related equipment and facilities	55,937,955	19,599,812
Uncompleted wells, equipment and facilities	13,581,022	71,150
Advances	5,618	65,722
Total costs	211,919,974	60,346,595
Less accumulated depreciation, depletion and amortization	(22,008,474)	(14,117,424)
Net capitalized costs	$189,911,500	$ 46,229,171

We follow the successful efforts method of accounting for our oil and gas producing activities. Costs to acquire mineral interests in oil and gas properties and to drill and equip development wells and related asset retirement costs are capitalized. Costs to drill exploratory wells are capitalized pending determination of whether the wells have proved reserves. If we determine that the wells do not have proved reserves, the costs are charged to expense. Geological and geophysical costs, including seismic studies and costs of carrying and retaining unproved properties are charged to expense as incurred. We capitalize interest on expenditures for significant exploration and development projects that last more than six months while activities are in progress to bring the assets to their intended use. No interest was capitalized during the periods presented.

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depreciation, depletion, and amortization are eliminated from the property accounts, and the resultant gain or loss is recognized. On the retirement or sale of a partial unit of proved property, the cost is charged to accumulated depreciation, depletion, and amortization with a resulting gain or loss recognized in income. A sale of a significant property is treated as discontinued operations. In 2010 we sold our interest in our Cinco Terry property and reflected the gain on sale and current and prior operating results as discontinued operations.

Capitalized amounts attributable to proved oil and gas properties are depleted by the unit-of-production method over proved reserves using the unit conversion ratio of six mcf of gas to one bbl of oil. Depreciation and depletion expense for oil and gas producing property and related equipment was $8.9 million, $3.2 million, and $7.0 million for the years ended December 31, 2010, 2009, and 2008, respectively.

Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. We recorded no unproved property impairment during the year ended December 31, 2010, $0.6 million during the year ended December 31, 2009, and none in 2008. The 2009 impairment resulted from a write-off of $0.4 million in acreage costs in the Boomerang Prospect in Kentucky as well as a $0.2 million write-off on the LeBlanc Prospect in Louisiana and the West Greene Field in North Dakota.

Capitalized costs related to proved oil and gas properties, including wells and related equipment and facilities, are evaluated for impairment based on an analysis of undiscounted future net cash flows. If undiscounted cash flows are insufficient to recover the net capitalized costs related to proved properties, then we recognize an impairment charge in income from operations equal to the difference between the net capitalized costs related to proved properties and their estimated fair values based on the present value of the related future net cash flows. We recorded an impairment charge of $0.3 million on our Giddings Field proved properties based on our analysis for the year ended December 31, 2010, and none for the year ended December 31, 2009. For the year ended December 31, 2008, we recorded an impairment of leasehold and well costs of $2.0 million on the East Flaxton Unit in North Dakota.

It is common for operators of oil and gas properties to request that joint interest owners pay for large expenditures, typically for drilling new wells, in advance of the work commencing. This right to call for cash advances is typically found in the operating agreement that joint interest owners in a property adopt. We record these advance payments in Advances in our property account and release this account when the actual expenditure is later billed to us by the operator.

On the sale of an entire interest in an unproved property for cash or cash equivalent, gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

Estimates of Proved Oil and Gas Reserves

Estimates of our proved reserves included in this report are prepared in accordance with U.S. generally accepted accounting principles ("GAAP") and SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions;
- and the judgment of the persons preparing the estimate.

Our proved reserve information included in this report was predominately based on evaluations prepared by independent petroleum engineers. Estimates prepared by other third parties may be higher or lower than those included herein. Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will be different from the quantities of oil and gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate.

In accordance with SEC requirements, beginning December 31, 2009, we based the estimated discounted future net cash flows from proved reserves on the unweighted arithmetic average of the prior 12-month commodity prices as of the first day of each of the months constituting the period and costs on the date of the estimate. In prior years, such estimates had been based on year end prices and costs. Future prices and costs may be materially higher or lower than these prices and costs which would impact the estimated value of our reserves.

The estimates of proved reserves materially impact DD&A expense. If the estimates of proved reserves decline, the rate at which we record depreciation and depletion expense will increase, reducing future net income. Such a decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields.

Oil and Gas Operations

Revenue Recognition

Revenues associated with sales of crude oil, natural gas, natural gas liquids and petroleum products, and other items are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery of goods occurs, either immediately or within a fixed delivery schedule that is reasonable and customary in the industry.

Revenues from the production of natural gas and crude oil properties in which we have an interest with other producers are recognized based on the actual volumes we sold during the period. Any differences between volumes sold and entitlement volumes, based on our net working interest, which are deemed to be non-recoverable through remaining production, are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are generally not significant.

Revenues from field servicing activities are recognized at the time the services are provided and earned as provided in the various contract agreements. gas gathering revenues are recognized at the time the natural gas is delivered at the destination point.

Accounts Receivable

We recognize revenue for our production when the quantities are delivered to or collected by the respective purchaser. Prices for such production are defined in sales contracts and are readily determinable based on certain publicly available indices. All transportation costs are included in marketing expense.

Accounts receivable from joint interest owners consist of uncollateralized joint interest owner obligations due within 30 days of the invoice date. Accounts receivable, oil and gas sales, consist of uncollateralized accrued revenues due under normal trade terms, generally requiring payment within 30 to 60 days of production. No interest is charged on past-due balances. Payments made on all accounts receivable are applied to the earliest unpaid items. We review accounts receivable periodically and reduce the carrying amount by a valuation allowance that reflects our best estimate of the amount that may not be collectible. We allowed for $213,000 at December 31, 2010, and no such allowance was considered necessary at December 31, 2009.

Revenue Payable

Revenue payable represents amounts collected from purchasers for oil and gas sales which are either revenues due to other revenue interest owners or severance taxes due to the respective state or local tax authorities. Generally, we are required to remit amounts due under these liabilities within 30 days of the end of the month in which the related production occurred.

Advances from Non-Operators

Advances from non-operators represent amounts collected in advance for joint operating activities. Such amounts are applied to joint interest accounts receivable as related costs are incurred.

Production Costs

Production costs, including compressor rental and repair, pumpers' salaries, saltwater disposal, ad valorem taxes, insurance, repairs and maintenance, expensed workovers and other operating expenses are expensed as incurred and included in lease operating expense on our consolidated statements of operations.

Exploration expenses include dry hole costs, delay rentals, and geological and geophysical costs.

Dependence on Major Customers

For the years ended December 31, 2010, 2009, and 2008, we sold substantially all of our oil and gas produced to seven purchasers. Additionally, substantially all of our accounts receivable related to oil and gas sales were due from those seven purchasers at December 31, 2010 and 2009. We believe that there are potential alternative purchasers and that it may be necessary to establish relationships with new purchasers as our production grows. However, there can be no assurance that we can establish such relationships and that those relationships will result in increased purchasers. Although we are exposed to a concentration of credit risk, we believe that all of our purchasers are credit worthy.

Dependence on Suppliers

Our industry is cyclical, and from time to time there is a shortage of drilling rigs, fracture stimulation services, equipment, supplies and qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. If the unavailability or high cost of drilling rigs, equipment, supplies or qualified personnel were particularly severe in the areas where we operate, we could be materially and adversely affected. We believe that there are potential alternative providers of drilling services and that it may be necessary to establish relationships with new contractors as our activity level and capital program grows. However, there can be no assurance that we can establish such relationships and that those relationships will result in increased availability of drilling rigs.

Other Property

Furniture, fixtures and equipment are carried at cost. Depreciation of furniture, fixtures and equipment is provided using the straight-line method over estimated useful lives ranging from three to five years. Gain or loss on retirement or sale or other disposition of assets is included in income in the period of disposition.

Our gas gathering system assets and field servicing assets are carried at cost. Depreciation of gas gathering system assets is provided using the straight line method over an estimated useful life of fifteen years. Depreciation of field servicing assets is provided using the straight line method over various useful lives ranging from three to ten years. Gain or loss on retirement or sale or other disposition of assets is included in income in the period of disposition.

Depreciation expense for other property and equipment was $86,931, $41,000, and $25,000 for the years ended December 31, 2010, 2009, and 2008, respectively.

Deferred financing costs

In connection with debt financings in we paid $2.9 million and $1.0 million in fees in the years ended December 31, 2010 and 2009, respectively. These fees were recorded as deferred financing costs and are being amortized over the life of the loans using the straight line method as the debt is in the form of a line of credit. Amortization of deferred financing costs for the years ended December 31, 2010, 2009, and 2008 were $1.2 million $1.2 million and $1.7 million, respectively.

Derivative Financial Instruments

We use commodity derivative financial instruments, typically options and swaps, to manage the risk associated with fluctuations in oil and gas prices. Derivative instruments (including certain derivative instruments embedded in other contracts) are recorded in the balance sheet as either an asset or liability measured at its fair market value. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement and requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. Our oil and gas price derivative contracts are not designated as hedges. These instruments have been marked-to-market through earnings.

Asset Retirement Obligation

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives, in accordance with applicable federal, state and local laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value as of the asset's inception, with an offsetting increase to proved properties. Periodic accretion of discount of the estimated liability is recorded as accretion expense in the consolidated statements of operations.

Our liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of wells and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Our liability for asset retirement obligations was approximately $4.5 million and $2.0 million at December 31, 2010 and 2009, respectively. See Note 7 — "Asset Retirement Obligations" to our consolidated financial statements for more information.

Share Based Compensation

The Company estimates the fair value of share-based payment awards made to employees and directors, including stock options, restricted stock and employee stock purchases related to employee stock purchase plans, on the date of grant using an option-pricing model. The value of the portion of the award that is ultimately expected to vest is recognized as an expense ratably over the requisite service periods. Awards that vest only upon achievement of performance criteria are recorded only when achievement of the performance criteria is considered probable. We estimate the fair value of each share-based award using the Black-Scholes option pricing model or a lattice model. These models are highly complex and dependent on key estimates by management. The estimates with the greatest degree of subjective judgment are the estimated lives of the stock-based awards, the estimated volatility of our stock price, and the assessment of whether the achievement of performance criteria is probable.

Income Taxes

We account for income taxes under the liability method. Deferred tax assets and liabilities are determined based on differences between financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse.

We recognize liabilities for uncertain income tax positions based on a two-step process. The first step is to evaluate the tax position for recognition by determining if the weight of available evidence indicates that it is more likely than not that the position will be sustained on audit, including resolution of related appeals or litigation processes, if any. The second step requires us to estimate and measure the tax benefit as the largest amount that is more than 50% likely to be realized upon ultimate settlement. It is inherently difficult and subjective to estimate such amounts, as we must determine the probability of various possible outcomes. We reevaluate these uncertain tax positions on a quarterly basis or when new information becomes available to management. These reevaluations are based on factors including, but not limited to, changes in facts or circumstances, changes in tax law, successfully settled issues under audit, expirations due to statutes, and new audit activity. Such a change in recognition or measurement could result in the recognition of a tax benefit or an increase to the tax accrual. We had no uncertain tax positions at December 31, 2010, or 2009.

We classify interest related to income tax liabilities as income tax expense, and if applicable, penalties are recognized as a component of income tax expense. The income tax liabilities and accrued interest and penalties that are anticipated to be due within one year of the balance sheet date are presented as current liabilities in our consolidated balance sheets.

Loss per Common Share

Basic net income or loss per common share is computed by dividing the net income or loss attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income or loss per common share is calculated in the same manner, but also considers the impact to net income and common shares for the potential dilution from stock options, stock warrants and any other outstanding convertible securities.

We have issued potentially dilutive instruments in the form of our restricted common stock granted and not yet issued, common stock warrants and common stock options granted to our employees. There were 13,862,360 and

18,097,869 dilutive securities outstanding at December 31, 2010 and 2009, respectively. We did not include any of these instruments in our calculation of diluted loss per share during the period because to include them would be anti-dilutive due to our net loss during the periods.

Reclassification of Prior-Year Balances

Certain prior-year balances in the consolidated financial statements have been reclassified to correspond with current-year classifications. As a result of the sale of our Cinco Terry property on October 29, 2010, we reclassified the gain on sale and all prior operating income and related interest expense for this property as discontinued operations.

Recently Issued Accounting Pronouncements

In January 2010, the FASB issued ASC 2010-06, Improving Disclosures about Fair Value Measurements (ASC 820-10). These new disclosures require entities to separately disclose amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and the reasons for the transfers. In addition, in the reconciliation for fair value measurements for Level 3, entities should present separate information about purchases, sales, issuances, and settlements. This guidance is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances and settlements in the roll forward of activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010 and for interim periods within those fiscal years. Our adoption of the disclosures, excluding the Level 3 activity disclosures, did not have a material impact on our notes to the condensed consolidated financial statements. See Note 3 — Fair Value of Financial Instruments for additional information. We are still evaluating the impact of the Level 3 disclosure requirements on our notes to the consolidated financial statements.

In February 2010, the FASB issued ASC 2010-09, Amendments to Certain Recognition and Disclosure Requirements, related to subsequent events under ASC 855, Subsequent Events. This guidance states that if an entity is and SEC filer, it is required to evaluate subsequent events for disclosure through the date that the financial statements are issued. We adopted this guidance as of February 2010 and have included the required disclosures in our condensed consolidated financial statements. See Note 16 — Subsequent Events for additional information.

NOTE 3 — FAIR VALUE OF FINANCIAL INSTRUMENTS

Accounting standards define fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The standards also establish a framework for measuring fair value and a valuation hierarchy based upon the transparency of inputs used in the valuation of an asset or liability. Classification within the hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The valuation hierarchy contains three levels:

- *Level 1* — Quoted prices (unadjusted) for identical assets or liabilities in active markets
- *Level 2* — Quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; and model-derived valuations whose inputs or significant value drivers are observable
- *Level 3* — Significant inputs to the valuation model are unobservable

We used the following fair value measurements for certain of our assets and liabilities during the years ended December 31, 2010 and 2009:

Level 2 Classification:

Derivative Instruments

At December 31, 2010 and 2009, the Company had commodity derivative financial instruments in place. The Company does not apply hedge accounting, therefore, the changes in fair value subsequent to the initial measurement are recorded in income. The estimated fair value amounts of the Company's derivative instruments have been determined at discrete points in time based on relevant market information which resulted in the Company classifying such derivatives as Level 2. Although the Company's derivative instruments are valued using public indexes, the instruments themselves are traded with unrelated counterparties and are not openly traded on an exchange. See footnote 4 — Financial Instruments and Derivatives, for additional information.

As of December 31, 2010 and 2009, the Company's derivative contracts were with major financial institutions with investment grade credit ratings which are believed to have a minimal credit risk. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above; however, the Company does not anticipate such nonperformance.

The following tables present recurring financial assets and liabilities which are carried at fair value as of December 31, 2010 and 2009:

	Fair Value Measurements on a Recurring Basis December 31, 2010		
	Level 1	Level 2	Level 3
Commodity derivatives	$—	$ —	$—
Total assets at fair value	$—	$ —	$—
Commodity derivatives	$—	$777,952	$—
Total liabilities at fair value	$—	$777,952	$—

	Fair Value Measurements on a Recurring Basis December 31, 2009		
	Level 1	Level 2	Level 3
Commodity derivatives	$—	$2,353,686	$—
Total assets as fair value	$—	$2,353,686	$—
Commodity derivatives	$—	$ 69,136	$—
Total liabilities at fair value	$—	$ 69,136	$—

NOTE 4 — FINANCIAL INSTRUMENTS AND DERIVATIVES

We enter into certain commodity derivative instruments which are effective in mitigating commodity price risk associated with a portion of our future monthly natural gas and crude oil production and related cash flows. Our oil and gas operating revenues and cash flows are impacted by changes in commodity product prices, which are volatile and cannot be accurately predicted. Our objective for holding these commodity derivatives is to protect the operating revenues and cash flows related to a portion of our future crude oil sales from the risk of significant declines in commodity prices. We have not designated any of our commodity derivatives as hedges under ASC 815.

As of December 31, 2010, the estimated fair values of our commodity derivatives were:

Commodity	Type	Volume/ Month	Duration	Price	Fair Market Value
Oil	Buy - CALL	4562	Jan 11 - Dec 11	82.25	$ 797,111
Oil	Buy - PUT	4,800 bbls	Jan 11 - Dec 11	80.00	(425,732)
Oil	Buy - PUT	4,600 bbls	Jan 12 - Dec 12	80.00	(291,803)
Oil	Buy - PUT	1400	Jan 11 - Dec 11	75.00	28,869
Oil	Buy - PUT	3042	Jan 11 - Dec 11	75.00	63,062
Oil	Buy - PUT	1525	Jan 12 - Dec 12	75.00	90,392
Oil	Buy - PUT	150 bbl per day	Jan 11 - Mar 11	60.00	49
Oil	Buy - PUT	150 bbl per day	Jan 11 - Mar 11	52.00	2
Oil	Buy - PUT	200 bbl per day	Jan 11 - Dec 11	75.00	126,124
Oil	Collar	4,178 bbls	Jan 12 - Dec 12	80.00 - 100.00	(131,921)
Oil	Collar	5,000 bbls	June 10 - Dec 11	70.00 - 82.25	(725,170)
Oil	Sell - CALL	4562	Jan 11 - Dec 11	90.00	(503,117)
Oil	Sell - CALL	1400	Jan 11 - Dec 11	95.00	(109,174)
Oil	Sell - CALL	3042	Jan 11 - Dec 11	97.20	(203,728)
Oil	Sell - CALL	1525	Jan 12 - Dec 12	108.00	(114,902)
Oil	Sell - CALL	200 bbl per day	Jan 11 - Dec 11	100.00	(333,332)
Oil	Sell - PUT	4562	Jan 11 - Dec 11	52.00	(7,078)
Oil	Sell - PUT	1400	Jan 11 - Dec 11	60.00	(6,497)
Oil	Sell - PUT	3042	Jan 11 - Dec 11	60.00	(14,203)
Oil	Sell - PUT	1525	Jan 12 - Dec 12	55.00	(20,624)
Oil	Swap	435 bbls	Jan 11 - Dec 11	85.25	(44,299)
Oil	Swap	2,250 bbls	Jan 11 - Dec 11	85.00	(89,085)
Natural Gas	Collar	12,500 mmbtu	Jan 11 - Dec 11	5.00 - 8.20	94,505
Natural Gas	Collar	4,165 mmbtu	Jan 11 - Dec 11	5.00 - 8.95	31,801
Natural Gas	Collar	10,000 mmbtu	Jan 12 - Dec 12	5.00 - 9.82	69,012
Natural Gas	Collar	47,600 mmbtu	Jan 11 - Dec 11	5.50 - 7.10	549,074
Natural Gas	Collar	47,300 mmbtu	Jan 12 - Dec 12	5.00 - 8.40	302,517
Natural Gas	Swap	3,400 mmbtu	Jan 11 - Dec 11	5.98	52,047
Natural Gas	Swap	3,000 mmbtu	Jan 12 - Dec 12	6.15	38,148
					$(777,952)

During the year ended December 31, 2010, we recognized a gain of $0.8 million related to oil and natural gas derivative contracts which included $3.9 million of realized gain related to settled contracts and $3.1 million of unrealized losses related to unsettled contracts. Unrealized gains and losses are based on the changes in the fair value of derivative instruments covering positions beyond December 31, 2010. During the year ended December 31, 2009, we incurred a loss of $2.3 million related to oil and natural gas derivative contracts which included $5.4 million of realized gain related to settled contracts, and $7.7 million of unrealized losses related to unsettled contracts. During the year ended December 31, 2008, we incurred a gain of $7.3 million related to derivative contracts. Included in this gain was $1.8 million of realized losses related to settled contracts, and $9.1 million of unrealized gains related to unsettled contracts.

NOTE 5 — ACQUISITIONS

Triad

On February 12, 2010, the Company completed the acquisition of privately-held Triad Energy Corporation and certain of its affiliated entities (collectively, "Triad"), an Appalachian Basin focused energy company, through a bankruptcy proceeding (the "Triad Acquisition"). The Triad Acquisition was completed to expand the assets and operations of Magnum Hunter in the Appalachia region. We acquired substantially all of the assets of Triad, which primarily consisted of oil and gas property interests in approximately 2,000 operated wells and included over 87,000 net mineral acres located in the states of Kentucky, Ohio, and West Virginia, a natural gas pipeline (Eureka Hunter Pipeline), two commercial salt water disposal facilities, three drilling rigs, workover rigs, and other oilfield equipment. These assets are now held by the Company's wholly-owned subsidiaries, Triad Hunter, LLC, Alpha Hunter Drilling, LLC, Hunter Disposal, LLC, Eureka Hunter Pipeline, LLC, and Hunter Real Estate, LLC.

The acquisition of Triad is accounted for using the acquisition method of accounting, which requires the net assets acquired to be recorded at their fair values. Due to our continuing evaluation of the fair values of the assets acquired in the acquisition of the Triad Energy assets, we determined the proper fair market value of the gas gathering system assets was $10 million and unproved oil and gas properties was $12.4 million. This represents an increase in gas gathering system assets of $8.9 million and a decrease in unproved oil and gas properties of $8.9 million from the amounts initially estimated. The following table summarizes the purchase price and the fair values of the net assets acquired as of December 31, 2010:

Fair value of total purchase price:	
Cash consideration	$ 8,000,000
Payment of Triad senior and other debt	55,210,910
Assumption of equipment indebtedness	3,411,816
Issuance of $15,000,000 stated value Series B Preferred Stock	14,982,000
Total	$81,604,726
Amounts recognized for assets acquired and liabilities assumed:	
Working capital	$ 4,195,113
Proved oil and gas properties	49,708,193
Unproved oil and gas properties	12,386,212
Gas gathering system assets	10,000,000
Field servicing equipment	7,576,000
Asset retirement obligation	(2,260,792)
Total	$81,604,726
Working capital acquired was as follows:	
Cash	$ 3,710,610
Accounts receivable	2,404,514
Prepaid expenses	222,521
Inventory	684,656
Other current assets	553,139
Accounts payable	(1,087,133)
Accrued liabilities	(365,256)
Revenue payable	(1,927,938)
Total working capital acquired	$ 4,195,113

Because Triad and certain of its affiliated entities had been operating under Chapter 11 of the Federal Bankruptcy Code since December 2008, the acquisition agreement did not include customary indemnification provisions, but did contain closing conditions and representations and warranties that are typical for a transaction of this nature.

In connection with the Triad Acquisition and pursuant to the Bankruptcy Order on February 12, 2010, we issued, in the aggregate, 4,000,000 shares of our Series B Preferred Stock with a stated value of $15,000,000. In June 2010, all outstanding shares of Series B Preferred Stock were either converted into shares of common stock of the Company or redeemed by the Company for cash. See Note 10 — Shareholders' Equity for additional information.

PostRock

On December 24, 2010, Magnum Hunter Resources Corporation and Triad Hunter, LLC entered into a Purchase and Sale Agreement, pursuant to which Triad agreed to purchase certain oil and gas properties and leasehold mineral interests and related assets located in Wetzel and Lewis Counties, West Virginia and certain additional assets. The Purchase Agreement provided for the acquisition to be completed in two phases. Both phases are effective as of November 1, 2010.

The first phase of the acquisition closed on December 30, 2010. Total consideration paid in the first closing was approximately $31.0 million which consisted of 2,255,046 shares of common stock valued at approximately $17.1 million on December 30, 2010 and a cash payment of approximately $13.9. See Note 10 — Shareholders' Equity for additional information.

The acquisition of the PostRock assets is accounted for using the acquisition method as set out in ASC 805, *Business Combinations*, which requires the net assets acquired to be recorded at their fair values. The fair value of the net assets acquired approximated the $31.0 million in consideration paid.

The following table summarizes the purchase price and the fair values of the net assets acquired as of December 31, 2010:

2,255,046 shares of common stock issued on December 30, 2010 at $7.58 per share	$17,093,248
Cash paid December 30, 2010	13,938,891
Total	$31,032,139
Amounts recognized for assets acquired and liabilities assumed:	
Working capital	$ (61,109)
Oil and gas properties	30,959,698
Equipment and other fixed assets	150,550
Asset retirement obligation	(17,000)
Total	$31,032,139
Working capital acquired	
Transfer tax payable	$ (61,109)
	$ (61,109)

The second phase of the acquisition of the Purchased Assets closed on January 14, 2011. See Note 16 — Subsequent Events for additional information.

The following summary, prepared on a pro forma basis, presents the results of operations for the years ended December 31, 2010, and 2009, as if the acquisition of Triad and Post Rock, along with transactions necessary to finance the acquisitions, had occurred as of the beginning of the respective periods. The pro forma information includes the effects of adjustments for interest expense, depreciation and depletion expense, and dividend expense. The pro forma results are not necessarily indicative of what actually would have occurred if the acquisition had been completed as of the beginning of each period presented, nor are they necessarily indicative of future consolidated results.

	For the Year Ended December 31,	
	2010	2009
	(In thousands)	
Total operating revenue	$ 36,773	$ 34,953
Total operating costs and expenses	55,362	41,543
Operating income (loss)	(18,589)	(6,590)
Interest expense and other	3,859	(10,807)
Net loss attributable to Magnum Hunter Resources Corporation	(14,730)	(17,397)
Dividends on preferred stock	(2,664)	(1,153)
Net loss attributable to common stockholders	$(17,394)	$(18,550)
Loss per common share, basic and diluted	$ (0.26)	$ (0.34)

The consolidated statement of operations includes Triad's revenue of $21.3 million for the year ended December 31, 2010 and Triad's operating income of $3.2 million for the year ended December 31, 2010. Amounts attributable to Post Rock in the 2010 consolidated statement of operations were insignificant.

NOTE 6 — DISCONTINUED OPERATIONS

On October 29, 2010, the Company entered into a definitive purchase and sale agreement with a subsidiary of Approach Resources, Inc. ("Approach") for the sale to Approach of Magnum Hunter's 10.0% non-operated working interest in the Cinco Terry property located in Crockett County, Texas, which closed on October 29, 2010. Total cash consideration of the sale to Approach was $21.5 million, subject to customary adjustments. We recorded a gain of approximately $6.7 million on the disposal. The proceeds from the sale were used to pay down our revolving credit loan and to fund expenditures under our capital budget. Our borrowing base under the revolving credit agreement was reduced to $65 million from $75 million, at that time, as a result of the sale. The operating results of the Cinco Terry property for the years ended December 31, 2010, 2009 and 2008 have been reclassified as discontinued operations in the consolidated statements of operations as detailed in the table below:

	Year Ended December 31		
	2010	2009	2008
Oil and Gas Sales and other revenues from discontinued operations	$ 4,850,496	$ 3,428,132	$ 4,293,660
Operating expenses from discontinued operations	(2,613,153)	(2,337,668)	(1,300,933)
Interest expense from discontinued operations	(377,500)	(645,249)	(410,706)
Gain on sale of discontinued operations	6,659,611	—	—
Income tax expense on sale of discontinued operations	(62,643)	—	—
Net income from discontinued operations	$ 8,456,811	$ 445,215	$ 2,582,021

At December 31, 2009, on our consolidated balance sheet, the assets relating to the Cinco Terry property are classified as assets held for sale and the liabilities are classified as liabilities associated with discontinued operations.

NOTE 7 — ASSET RETIREMENT OBLIGATIONS

The Company accounts for asset retirement obligations based on the guidance of ASC 410 which addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. ASC 410 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the estimated useful life of the related asset. We have included estimated future costs of abandonment and dismantlement in our successful efforts amortization base and amortize these costs as a component of our depreciation, depletion, and accretion expense in the accompanying consolidated financial statements.

The following table summarizes the Company's asset retirement obligation transactions during the years ended December 31:

	2010	2009
Asset retirement obligation at beginning of period	$2,032,306	$1,589,197
Purchased in Sharon Resources acquisition	—	150,211
Assumed in Triad Acquisition	2,260,792	—
Assumed in PostRock Acquisition	17,000	—
Liabilities incurred	45,797	150,822
Liabilities settled	(276,414)	(22,914)
Accretion expense	375,846	164,990
Revisions in estimated liabilities	—	—
Asset retirement obligation at end of period	$4,455,327	$2,032,306

NOTE 8 — NOTES PAYABLE

Notes payable at December 31, 2010 and 2009 consisted of the following:

	2010	2009
Note payable due February 1, 2010, 4.75%	$ —	$ 44,157
Various equipment notes payable with maturity dates April 2012 to August 2015, interest rates of 0.00% — 6.34%	3,151,070	—
Senior revolving credit facility due November 23, 2012, 4.5% Tranche A and 5.5% tranche B		
Tranche A at 4.5% due November 23, 2012	23,500,000	13,000,000
Tranche B at 5.5%, due November 30, 2011	6,500,000	
	$33,151,070	$13,044,157
Less: current portion	(7,132,455)	(44,157)
Total Long-Term Debt	$26,018,615	$13,000,000

The following table presents the approximate annual maturities of debt:

2011	$ 7,132,455
2012	24,135,267
2013	657,705
2014	639,765
Thereafter	585,878
	$33,151,070

Notes Payable

On April 10, 2009, we executed a promissory note for $217,336 with a finance company to finance our various insurance policies. The interest rate on the note was 4.75% with payments of $22,210 per month beginning May 1, 2009 and the final payment was February 1, 2010. The note was secured by the insurance policies. At December 31, 2010 and 2009, the outstanding balance on the note was $0 and $44,157, respectively.

In connection with the Triad acquisition in February 2010, the Company assumed various notes payable for equipment which have a principal balance of $3,151,070 at December 31, 2010 and are collateralized by the financed equipment.

Revolving Credit Facility

On November 23, 2009, the Company entered into a credit agreement with Bank of Montreal which provided for an asset-based, three-year senior secured revolving credit facility with an initial borrowing base availability of $25 million.

On February 12, 2010, the Company entered into an amended and restated credit agreement with Bank of Montreal and Capital One, N.A. This restated credit agreement amended and restated in its entirety the credit facility dated November 23, 2009. The restated credit agreement provides for an asset-based, senior secured revolving credit facility, referred to as the revolving facility, maturing November 23, 2012, and had an initial borrowing base of $70 million. The revolving facility is governed by a semi-annual borrowing base redetermination (on April 1 and November 1 of each year) derived from the Company's proved crude oil and natural gas reserves, and based on such redetermination, the borrowing base may be decreased or increased up to a maximum commitment level of $150 million. The initial $70 million borrowing base consisted of a $60 million A tranche and a $10 million B tranche.

On May 13, 2010, the Company's borrowing base under the revolving facility was increased from $70 million to $75 million. The tranche B facility was eliminated. The increase in the borrowing base reflected the increase in the Company's proved reserves at December 31, 2009 and the acquisition of the Triad Energy assets which closed in February 2010. Other new participating banks included UBS Loan Finance LLC, Amegy Bank National Association, and Key Bank National Association.

On November 30, 2010, the Company entered into a second amendment to the revolving facility, referred to as the second amendment. The second amendment reset the tranche A portion of the Company's borrowing base under the revolving facility at $65 million (due to the sale of the Company's Cinco Terry properties) and established the tranche B portion of the borrowing base at $6.5 million, subject to change (a) pursuant to any redetermination of the tranche A portion of the borrowing base in accordance with the provisions of the revolving facility and (b) as described in the paragraph below. This reflected an increase in the Company's total borrowing base from $65 million to $71.5 million. This new borrowing base reflected the increase in the Company's proved reserves at June 30, 2010 resulting from the Company's February 2010 acquisition of the Triad Energy assets out of bankruptcy, and as adjusted for the October 2010 divestiture of the Company's non-operated working interest in the Cinco Terry property in West Texas for total consideration of $21.5 million.

Pursuant to the second amendment, on November 30, 2010, the lenders made a tranche B term loan to the Company in the amount of $6.5 million associated with the Eureka Hunter Pipeline. The tranche B loan bears interest, which is payable not less frequently than quarterly, at the rate of 5.50% per annum and is due and payable in full on November 30, 2011, referred to as the tranche B maturity date, subject to required prepayments as a result of reductions in the tranche B borrowing base as set forth below. Prior to the tranche B maturity date, any increase in the tranche A portion of the Company's borrowing base as a result of a redetermination of the borrowing base that results in the tranche A portion exceeding $65 million will automatically and permanently reduce the amount of the tranche B portion of the borrowing base by the amount of such increase in the tranche A portion on a dollar for dollar basis. Also, prior to the tranche B maturity date, the tranche B portion of the borrowing base will be automatically and permanently reduced by a specified percentage of any net cash proceeds from the sale of certain capital assets, or from the issuance, incurrence or assumption of certain debt for borrowed money, relating to the Company's Eureka Hunter Pipeline. The tranche B portion of the borrowing base is principally intended to be utilized to fund the Company's development of the Eureka Hunter Pipeline.

The second amendment also designated Eureka Hunter Pipeline, LLC, a subsidiary of the Company, and Eureka Hunter's directly-owned subsidiary, as restricted subsidiaries for purposes of the revolving facility, and amended certain negative covenants of the revolving facility to reflect such subsidiaries' designation as restricted subsidiaries. The second amendment continued to permit the Company to make certain investments in Eureka Hunter.

The revolving facility has a commitment fee which ranges between 0.50% and 0.75%, based upon the unused portion of the borrowing base. Borrowings under the revolving facility will, at the Company's election, bear interest at either (i) an alternate base rate ("ABR") equal to the higher of (A) BMO's base rate, (B) the Federal Funds Effective Rate, plus 0.5% per annum and (C) the LIBO Rate for a one month interest period on such day, plus 1.0% or (ii) the adjusted LIBO Rate, which is the rate stated on Reuters BBA Libor Rates C2BORO1 market for one, two, three, six or twelve months, as adjusted for statutory reserve requirements for Eurocurrency liabilities, plus, in each of the cases described in (i) or (ii) above, an applicable margin ranging from 1.50% to 2.50% for ABR loans and from 2.50% to 3.50% for adjusted LIBO Rate loans. In the event a default occurs and is continuing under the revolving facility, the lenders may increase the interest rate then in effect by an additional 2% per annum plus the rate then applicable to ABR loans. Subject to certain permitted liens, the Company's obligations under the revolving facility are secured by a grant of a first priority lien on no less than 80% of the value of the proved oil and gas properties of the Company and its subsidiaries, including 90% of the total value of the oil and gas properties of the Company and its subsidiaries that are categorized as proved reserves that are both developed and producing as such terms are defined in the Definitions for Oil and Gas Reserves as promulgated by the Society of Petroleum Engineers.

At December 31, 2010 and 2009, the Company had loans outstanding under this revolving facility of $30 million and $13 million, respectively.

Covenants

The revolving credit facility, as amended, requires the Company to satisfy certain affirmative financial covenants, including maintaining (a) an interest coverage ratio (as such term is defined in the revolving credit facility) of not less than 2.5:1.0; (b) a ratio of total debt (as such term is defined in the revolving credit facility) to EBITDAX of not more than 4.0:1.0 for each fiscal quarter; and (c) a ratio of consolidated current assets (including available borrowing) to consolidated current liabilities of not less than 1.0:1.0. The Company is also required to enter into certain commodity price hedging agreements pursuant to the terms of the revolving credit facility. At December 31, 2010, we were in compliance with all of our covenants and had not committed any acts of default under the revolving credit facility.

NOTE 9 — SHARE BASED COMPENSATION

Under the 2006 Stock Incentive Plan, our common stock, common stock options, and stock appreciation rights may be granted to employees and other persons who contribute to the success of Magnum Hunter. Currently, 15,000,000 shares of our common stock are authorized to be issued under the plan, and 671,817 shares have been issued as of December 31, 2010.

We recognized share-based compensation expense of $6.4 million, $3.1 million, and $1.6 million for the year ended December 31, 2010, 2009, and 2008, respectively.

During November 2010, the compensation committee authorized the issuance of stock appreciation rights on 3,083,332 shares of common stock to the Chairman and Chief Executive Officer of the Company. The Stock appreciation rights have a base price of $6.09 and an estimated weighted average fair market value of $2.97 per share. The stock appreciation rights have a life of 5 years and vest upon certain performance and market conditions being met.

A summary of stock option and stock appreciation rights activity for the year ended December 31, 2010, 2009, and 2008 is presented below:

	2010		2009		2008	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Outstanding at beginning of period	7,117,000	$0.93	1,035,000	$3.11	1,125,000	$3.68
Granted	5,892,332	$4.70	6,107,000	$0.56	310,000	$1.90
Exercised	(52,500)	$2.05	—	$ —	—	$ —
Forfeited or expired	(177,550)	$1.36	(25,000)	$2.50	(400,000)	$3.80
Outstanding at end of period	12 ,779,282	$2.65	7,117,000	$0.93	1,035,000	$3.11
Exercisable at end of the year	7,563,750	$1.29	4,776,750	$0.98	902,500	$3.56

A summary of the Company's non-vested options and stock appreciation rights as of December 31, 2010, 2009, and 2008 is presented below:

Non-Vested Options	2010	2009	2008
Non-vested at beginning of period	2,340,250	432,500	575,000
Granted	5,892,332	6,107,000	310,000
Vested	(2,964,500)	(4,174,250)	(352,500)
Forfeited	(52,550)	(25,000)	(100,000)
Non-vested at December 31, 2010	5,215,532	2,340,250	432,500

Total unrecognized compensation cost related to the non-vested options was $10,429,909, $815,784, and $309,700 as of December 31, 2010, 2009, and 2008, respectively. The cost at December 31, 2010 is expected to be recognized over a weighted-average period of 2.79 years. At December 31, 2010, the aggregate intrinsic value for the outstanding options was $58,143,588; and the weighted average remaining contract life was 4.98 years.

The assumptions used in the fair value method calculation for the year ended December 31, 2010, 2009, and 2008 are disclosed in the following table:

	Year Ended December 31,		
	2010(1)	2009(1)	2008(1)
Weighted average fair value per option granted during the period(2)	2.65	0.37	1.36
Assumptions(3):			
Weighted average stock price volatility	79.32%	108 - 263%	104 - 105%
Weighted average risk free rate of return	1.78%	1.36 - 2.53%	1.87 - 2.69%
Weighted average expected term	4.24 years	4.23 years	3.25 years

(1) Our estimated future forfeiture rate is zero.

(2) Calculated using the Black-Scholes fair value based method for service and performance based grants and the Lattice Model for market based grants.

(3) The Company does not pay dividends on our common stock.

During 2010, the Company granted 58,856 fully vested shares of common stock to the Company's board members as payment of annual and meeting fees. The company issued 46,062 of these shares during 2010.

In November 2010, the Company granted 195,074 shares of restricted stock to the Chairman and Chief Executive Officer of the company which vest equally over three years.

A summary of the Company's non-vested shares as of December 31, 2010, 2009 and 2008 is presented below:

	2010		2009		2008	
Non-Vested Shares	Shares	Weighted Average Price per Share	Shares	Weighted Average Price per Share	Shares	Weighted Average Price per Share
Non-vested at beginning of year	2,310,000	$0.44	215,000	$2.04	75,000	$2.50
Granted	253,930	$5.45	4,168,181	$0.33	240,000	$1.90
Vested	(2,263,856)	$0.47	(2,048,181)	$0.43	(100,000)	$2.04
Forfeited	—	$ —	(25,000)	$2.50	—	$ —
Non-vested at end of year	300,074	$4.43	2,310,000	$0.44	215,000	$2.04

Total unrecognized compensation cost related to the above non-vested shares amounted to $1,180,324, $196,561, and $237,432 as of December 31, 2010, 2009, and 2008, respectively. The unrecognized compensation cost at December 31, 2010 is expected to be recognized over a weighted-average period of 2.88 years.

NOTE 10 — SHAREHOLDERS' EQUITY

Common Stock

During the years ended December 31, 2010, 2009, and 2008, the Company issued 2,539,317, 1,886,200, and 168,800, respectively, of the Company's common stock in correlation with share-based compensation which had fully vested to certain senior management and officers of the company.

On September 30, 2009, Magnum Hunter Resources Corporation issued 2,294,474 shares of the Company's common stock valued at approximately $2.68 million based on the closing stock price of $1.17, as consideration for the acquisition of 100% of the outstanding common stock of Sharon Hunter Resources, Inc.

On November 5, 2009, the Company sold, for gross proceeds of approximately $3.8 million, an aggregate of 2.3 million shares of the Company's common stock, together with one warrant for every five shares to purchase one share of the Company's common stock for each share of common stock purchased. Each warrant issued to a purchaser will (i) be exercisable for one share of the Company's common stock at any time after the shares of common stock underlying the warrant are registered with the SEC for resale pursuant to an effective registration statement, (ii) have a cash exercise price of $2.50 per share of the Company's common stock, and (iii) upon notice to the holder of the warrant, be redeemable by the Company for $0.01 per share of the Company's common stock underlying the warrant if (a) the Registration Statement as filed with the SEC is effective and (b) the average trading price of the Company's common stock as traded and quoted on the NYSE Amex equals or exceeds $3.75 per share for at least 20 days in any period of 30 consecutive days. The Company's common stock purchased in this transaction was issued pursuant to a prospectus supplement filed with the SEC in connection with a takedown from the Company's existing $100 million universal shelf registration statement on Form S-3, which became effective on October 15, 2009. Purchasers of this issuance of common shares by the Company included, amongst others, the Company's Chairman, Vice Chairman, Executive Vice President and Chief Financial Officer, and three other members of the Company's Board of Directors.

On November 6, 2009, the Company issued 601,652 shares of common stock valued at $1.1 million as a deposit on the Triad acquisition. The terms of the purchase agreement required Magnum to add additional shares to the deposit as required to maintain the fair market value of the common stock placed on deposit at a minimum value of $1.1 million. On November 20, 2009 and December 22, 2009, the Company issued 60,000 and 100,000 shares, respectively, to maintain the deposit balance as required. All shares on deposit were returned to the Company on February 23, 2010 and are now treasury shares.

On November 16, 2009, the Company sold 6,403,720 units, with each unit consisting of one of the Company's common shares and a one fifth of a warrant to purchase one common share, for gross proceeds of approximately $11.08 million, before deducting placement agent fees and estimated offering expenses, in a "registered direct" offering. The investors purchased the units at a purchase price of $1.73 per unit. The warrants, which represent the right to acquire an aggregate of up to 1,280,744 common shares, will be exercisable at any time on or after May 17, 2010 and prior to the 3-year anniversary of the closing of the transaction at an exercise price of $2.50 per share, which was 132% of the closing price of the Company's common shares on the NYSE Amex on November 10, 2009. The new equity capital raised in this offering satisfied the Company's minimum equity commitment required under the terms of the Asset Purchase Agreement in connection with the acquisition of Triad Energy Corporation which closed February 12, 2010.

The Company issued 187,482 shares of common stock in November 2009 at an average price of $1.76 per share pursuant to the At the Market sales agreement we had with Wm Smith & Co., our exclusive sales manager at that time. Sales of shares of our common stock, by Wm. Smith & Co. were made in privately negotiated transactions or in any method permitted by law deemed to be an "at the market" offering as defined in Rule 415 promulgated under the Securities Act of 1933, as amended, at negotiated prices, at prices prevailing at the time of sale or at prices related to such prevailing market prices, including sales made directly on the American Stock Exchange or sales made through a market maker other than on an exchange. Wm. Smith & Co. has made all sales using commercially reasonable efforts consistent with its normal sales and trading practices on mutually agreed upon terms between Wm. Smith & Co. and us.

During the year ended December 31, 2010, the Company issued 10,832,076 shares of common stock in open market transactions at an average price of $3.57 per share pursuant to an "At the Market" sales agreement (ATM) we have with our sales agent for total new proceeds of approximately $38.7 million. Sales of shares of our common stock by our sales agent have been made in privately negotiated transactions or in any method permitted by law deemed to be an "At The Market" offering as defined in Rule 415 promulgated under the Securities Act of 1933, as amended, at negotiated prices, at prices prevailing at the time of sale or at prices related to such prevailing market prices, including sales made directly on the NYSE Amex or sales made through a market maker other than on an exchange. Our sales agent has made all sales using commercially reasonable efforts consistent with its normal sales and trading practices on mutually agreed upon terms between our sales agent and us.

On March 17, 2010, the Company issued 55,932 common shares with a fair market value of approximately $165,000 for payment of services received in connection with the Triad Acquisition.

During the year ended December 31, 2010, the Company issued 7,536,654 shares of the Company's common stock upon the exercise of warrants for total proceeds of approximately $16.1 million.

During the year ended December 31, 2010, the Company issued 52,500 common shares upon the exercise of fully vested stock options for proceeds of approximately $125,000.

On June 7, 2010, the Company issued 1,000,000 shares of common stock pursuant to the conversion of 1,000,000 shares of the Company's Series B Convertible Preferred Stock.

On October 27, 2010, at the annual stockholders' meeting, shareholders approved an amendment to the Company's Certificate of Incorporation that increased the Company's authorized number of shares of Common Stock to 150,000,000 and approved the Magnum Hunter Resources Corporation Stock Incentive Plan, an amendment and restatement of the Company's 2006 Stock Incentive Plan which included increasing the authorized shares to be issued under the plan to 15,000,000.

On December 31, 2010, the Company issued 2,255,046 shares of common stock valued at approximately $17.1 million based on the closing stock price of $7.58 as consideration in the first closing of the PostRock acquisition.

Series A Convertible Preferred Stock

On September 26, 2008, the Company redeemed 2,563,712 shares of the Company's outstanding Series A Preferred Stock at an aggregate redemption price of $7,966,735. The shares were held by investment funds managed by Touradji Capital Management. Pursuant to the terms of the Preferred Stock Purchase Agreement, the Company was required to redeem all Series A Preferred Stock no later than October 2, 2008. After giving effect to the redemption, there were no shares of Series A Preferred Stock outstanding at December 31, 2008. The Series A Preferred Stock was retired in June 2010.

Series B Redeemable Convertible Preferred Stock

In connection with the Triad Acquisition and pursuant to the related Bankruptcy Order on February 12, 2010, we issued in the aggregate 4,000,000 shares of our Series B Preferred Stock, with an aggregate liquidation preference of $15 million to the secured creditors of the Triad entities as partial consideration for the Triad Acquisition. These holders of Series B Preferred were secured creditors of Triad in its Chapter 11 bankruptcy proceeding and the Series B Preferred was issued to them in partial satisfaction of their secured claims against Triad. The Series B Preferred Stock ranked senior to the Company's common stock and to the Company's 10.25% Series C Cumulative Perpetual Preferred Stock. Pursuant to the Certificate of Designation for the Series B Preferred Stock (the "Certificate of Designation"), the Series B Preferred Stock was entitled to dividends at a rate of 2.75% per annum payable quarterly (i) in shares of Series B Preferred Stock or (ii) subject to the receipt of any required consent under the Company's senior credit facility, in cash. In addition, the Series B Preferred Stock had a liquidation preference equal to the greater of (i) $3.75 per share, plus accrued and unpaid dividends, or (ii) the amount payable per share of common stock which the holder of Series B Preferred Stock would have received if such Series B Preferred Stock had been converted to common shares immediately prior to the liquidation event, plus accrued and unpaid dividends. At any time prior to the twentieth anniversary of the original issuance of Series B Preferred Stock, the holders of shares of Series B Preferred Stock could convert any or all of their Series B Preferred Stock into shares of the Company's common stock at a conversion ratio of one share of Series B Preferred Stock to one share of common stock, subject to certain adjustments. At any time following the second anniversary of the original issuance of Series B Preferred and prior to the twentieth anniversary of such original issuance, the holders of shares of Series B Preferred stock could tender their shares for redemption to the Company for a redemption price of $3.75 per Series B share, as adjusted. In addition, the Company could redeem the Series B Preferred Stock at a price of $3.75 per share, plus accrued and unpaid dividends, (a) at any time following February 12, 2012, or (b) if the average trading price of the Common Stock equaled or exceeded $4.74 per common share, as adjusted, for five consecutive trading days.

In June 2010, the Company redeemed 3,000,000 shares of our Series B Preferred Stock for a cash payment of approximately $11.3 million, and 1,000,000 shares of the Series B Preferred Stock were converted into 1,000,000 shares of our common stock. In June 2010, the Company retired the Series B Preferred Stock.

Series C Cumulative Perpetual Preferred Stock

On December 13, 2009, the Company sold 214,950 shares of our 10.25% Series C Cumulative Perpetual Preferred Stock, par value $0.01 per share and liquidation preference $25.00 per share (the *"Series C Preferred Stock"*) for net proceeds of $5.1 million. The Series C Preferred Stock cannot be converted into common stock of the Company, but may be redeemed by the Company, at the Company's option, on or after December 14, 2011 for par value or $25.00 per share. In the event of a change of control of the Company, the Series C Preferred Stock will be redeemable by the holders at $26.00 per share during the first twelve months after December 14, 2009, $25.50 during the second twelve months after December 14, 2009, and $25.00 thereafter, except in certain circumstances when the acquirer is considered a qualifying public company. The Company will pay cumulative dividends on the Series C Preferred Stock at a fixed rate of 10.25% per annum of the $25.00 per share liquidation preference. Because redemption is potentially outside the control of the Company, the Series C Preferred Stock is recorded outside of permanent shareholders' equity.

During the year ended December 31, 2010, the Company sold 2,594,506 shares of the Series C Preferred Stock under our ATM agreement for net proceeds of $63.4 million.

A summary of dividends paid by the Company for the years ended December 31, 2010, 2009, and 2008 is presented below:

	2010	2009	2008
Dividend on Series A Preferred Stock	—	—	(734,406)
Dividend on Series B Preferred Stock	(130,625)	—	—
Dividend on Series C Preferred Stock	(2,336,054)	(25,654)	—
Total dividends on Preferred Stock	(2,466,679)	(25,654)	(734,406)

Treasury Stock

On February 23, 2010 a total of 761,652 shares of common stock with a carrying value of $1,310,357, which were previously issued as a performance deposit on the Triad acquisition, were returned to the Company and are now held as treasury shares.

Unearned Common Stock in KSOP

During the year ended December 31, 2010, the Company loaned 153,300 shares of our common stock to the KSOP plan at a total cost of $603,613.

Noncontrolling Interests

In connection with the Williston Basin acquisition in 2008, the Company entered into equity participation agreements with the lenders pursuant to which the Company agreed to pay to the lenders an aggregate of 12.5% of all distributions paid to the owners of PRC Williston, which at this time is majority owned by Magnum Hunter

Resources. The equity participation agreements were valued at $3,401,655 and accounted for as a noncontrolling interest in PRC Williston.

	2010	2009	2008
Noncontrolling interest at beginning of period	$1,321,753	$1,384,909	$ 3,025,375
Income/(Loss) to noncontrolling interest	128,586	(63,156)	(1,640,466)
Noncontrolling interest at end of period	$1,450,339	$1,321,753	$ 1,384,909

Common Stock Warrants

During 2005, the Company issued 5,775,650 five year warrants to purchase an equal number of shares of the Company's common stock at an exercise price of $2.00 per share in conjunction with private placement sales of common stock. The Company also issued 25,000 shares of its common stock and 25,000 warrants with a five year term with an exercise price of $2.00, valued in the aggregate at $50,000, as partial consideration for a working interest in an oil and gas property.

During 2006, the Company issued 871,500 warrants to purchase an equal number of shares of the Company's common stock at an exercise price of $3.00 per share in conjunction with private placement sales of common stock. The warrants have a term of five years from the date of issuance. The Company also issued 326,812 warrants to purchase an equal number of shares of the Company's common stock at an exercise price of $3.00 per share along with a cash payment for commission fees.

In association with common stock sales on November 5, 2009, the Company issued 457,982 common stock warrants. Each warrant issued to a purchaser has a term of 3 years and (i) is exercisable for one share of the Company's common stock at any time after the shares of common stock underlying the warrant are registered with the SEC for resale pursuant to an effective registration statement, which was June 12, 2010, (ii) has a cash exercise price of $2.50 per share of the Company's common stock, and (iii) upon notice to the holder of the warrant, is redeemable by the Company for $0.01 per share of the Company's common stock underlying the warrant if (a) the Registration Statement as filed with the SEC is effective and (b) the average trading price of the Company's common stock as traded and quoted on the NYSE Amex equals or exceeds $3.75 per share for at least 20 days in any period of 30 consecutive days.

On November 16, 2009, the Company issued 1,280,744 common stock warrants. The warrants, which represent the right to acquire an aggregate of up to 1,280,744 common shares, will be exercisable at any time on or after May 17, 2010 and have a term of 3 years, at an exercise price of $2.50 per share, which was 145% of the closing price of the Company's common shares on the NYSE AMEX on November 11, 2009.

During the year ended December 31, 2010, 251,500 of our $3.00 common stock warrants, 1,562,504 of our $2.50 common stock warrants, and 5,722,650 of our $2.00 common stock warrants were exercised for total combined proceeds of approximately $16.1 million and 78,000 of our $2.00 common stock warrants expired.

A summary of warrant activity for the years ended December 31, 2010, 2009, and 2008 is presented below:

	2010		2009		2008	
	Shares	Weighted - Average Exercise Price	Shares	Weighted - Average Exercise Price	Shares	Weighted - Average Exercise Price
Outstanding at beginning of year	8,577,688	$2.15	6,838,962	$2.15	6,838,962	$2.15
Granted	—	$ —	1,738,726	$2.50	—	$ —
Exercised, forfeited, or expired	(7,614,654)	$2.14	—	$ —	—	$ —
Outstanding at end of year	963,034	$2.91	8,577,688	$2.22	6,838,962	$2.15
Exercisable at end of year	963,034	$2.91	6,838,962	$2.15	6,838,962	$2.15

At December 31, 2010, the aggregate intrinsic value for warrants was $4.1 million; and the weighted average remaining contract life was .49 years.

NOTE 11 — INCOME TAXES

At December 31, 2010, we had available for U.S. federal income tax reporting purposes, a net operating loss (NOL) carry forward for regular tax purposes of approximately $55 million which expires in varying amounts during the tax years 2019 through 2030. We also have approximately $2.5 million of depletion carryover which has no expiration. Approximately $5 million of our NOL relates to the 2009 acquisition of Sharon Hunter Resources Inc. and the utilization of that portion of the NOL is limited on an annual basis under Section 382 as discussed below. No provision for federal income tax expense or benefit is reflected on the statement of operations for the years ended December 31, 2010, and 2009, and 2008 because we are uncertain as to our ability to utilize our NOL in the future.

Internal Revenue Code ("I.R.C.") Section 382 imposes additional limitations on a corporation's ability to utilize its NOL carryforwards in the tax years following an "ownership change". For this purpose, an ownership change results from stock transactions that increase the ownership of certain existing and new stockholders in the corporation by more than 50 percentage points during the previous three year testing period. The minimum annual NOL utilization limitation amount is determined by multiplying the company's market capitalization value on the ownership change date by the applicable federal interest rate. The amount of the limitation may, under certain circumstances, be increased to reflect both recognized and deemed recognized built-in gains that occur, or are deemed to occur, during the five-year period immediately following the ownership change. An ownership change occurred in 2007 that subjected approximately $13 million of NOL carryforwards to the annual NOL utilization limitations provided for in Section 382 in addition to the limitation on the Sharon Resources NOL discussed above. However, the annual NOL utilization limitations applicable to these ownership changes are not expected to have a material impact on our ability to utilize the NOL carryforwards generated in those prior years.

The following is a reconciliation of the reported amount of income tax expense (benefit) for the years ended December 31, 2010, 2009 and 2008 to the amount of income tax expense that would result from applying domestic federal statutory tax rates to pretax income:

	2010	2009	2008
		(In thousands)	
Statutory tax expense (benefit)	$(4,692)	$(5,142)	$(2,341)
State income tax	63	—	—
Effect of permanent differences	346	6	544
Change in valuation allowance	4,346	5,136	1,797
Total Tax Expense	$ 63	$ —	$ —

The components of our deferred income taxes were as follows for the years ended December 31, 2010 and 2009:

	2010	2009	2008
		(In thousands)	
Deferred tax assets:			
Net operating loss carryforwards	$ 19,275	$ 15,302	$10,551
Asset retirement obligations	1,515	691	540
Share based compensation	2,768	2,412	1,397
Depletion carry forwards	870	455	—
Deferred tax liability:			
Property and equipment	(3,301)	(2,593)	(4,992)
Net deferred tax assets	21,217	16,267	7,496
Valuation allowances	(21,217)	(16,267)	(7,496)
Net deferred tax	$ —	$ —	$ —

The tax years 2007-2010 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject. The tax years 2006-2010 remain open for the Texas Franchise tax.

NOTE 12 — OTHER INFORMATION

Quarterly Data (Unaudited)

The following tables set forth unaudited summary financial results on a quarterly basis for the three most recent years.

	Quarter Ended				
2010	**March 31**	**June 30**	**September 30**	**December 31**	**Total Year**
Total revenue	$ 6,654,958	$ 8,401,772	$ 7,920,002	$ 9,746,941	$ 32,723,673
Loss from operations	(4,492,686)	(6,451,088)	(3,394,376)	(5,071,043)	(19,409,193)
Net loss attributable to common shareholders	(4,049,059)	(5,993,503)	(4,323,657)	(1,900,389)	(16,266,608)
Basic and diluted loss per common share	$ (0.07)	$ (0.10)	$ (0.06)	$ (0.02)	$ (0.25)
2009					
Total revenue	$ 1,095,635	$ 1,716,390	$ 1,587,778	$ 2,443,766	$ 6,843,569
Loss from operations	(1,685,337)	(1,290,856)	(2,869,461)	(4,771,537)	(10,617,191)
Net loss attributable to common shareholders	(1,371,283)	(3,393,576)	(3,052,222)	(7,332,782)	(15,149,863)
Basic and diluted loss per common share	$ (0.04)	$ (0.09)	$ (0.08)	$ (0.18)	$ (0.39)
2008					
Total revenue	$ 2,541,935	$ 3,287,493	$ 4,314,438	$ 1,445,915	$ 11,589,781
Income (loss) from operations	(927,300)	656,734	(428,286)	$(12,758,175)	(13,457,027)
Net loss attributable to common shareholders	(1,634,205)	(1,882,826)	(535,538)	(3,568,171)	(7,620,740)
Basic and diluted loss per common share	$ (0.05)	$ (0.05)	$ (0.01)	$ (0.10)	$ (0.21)

Supplemental Oil and Gas Disclosures (Unaudited)

The following table sets forth the costs incurred in oil and gas property acquisition, exploration, and development activities.

	2010	**2009**	**2008**
Purchase of non-producing leases	$ 46,683,478	$ 2,602,387	$ 1,410,023
Purchase of producing properties	53,116,350	3,288,174	—
Exploration costs	43,466,026	3,794,254	5,796,608
Development costs	13,640,669	6,798,142	11,607,005
Asset retirement obligation	2,170,849	278,119	93,153
	$159,077,372	$16,761,076	$18,906,789

Oil and Gas Reserve Information

Proved oil and gas reserve quantities are based on estimates prepared by Cawley, Gillespie & Associates, Inc. and DeGolyer & MacNaughton, Magnum Hunter's third party reservoir engineering firms. There are numerous uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production and timing of development expenditures. The following reserve data only represent estimates and should not be construed as being exact.

Total Proved Reserves

	Crude Oil and Condensate (Mbbl)	Natural Gas (Mcf)
Balance December 31, 2007	2,369.7	2,082.0
Extensions, discoveries and other additions	698.0	2,655.9
Revisions of previous estimates	(506.6)	(143.8)
Production	(151.8)	(341.1)
Balance December 31, 2008	2,409.3	4,253.0
Extensions, discoveries and other additions	982.3	2,087.3
Revisions of previous estimates	1,330.2	34.1
Purchases of reserves in place	83.4	3,468.0
Sales of reserves in place	(16.4)	(20.5)
Production	(180.3)	(457.7)
Balance December 31, 2009	4,608.5	9,364.2
Revisions of previous estimates	(112.4)	541.1
Purchase of reserves	3,328.8	22,249.7
Extensions, discoveries, and other additions	890.5	13,822.1
Sale of reserves	(1,506.6)	(5,298.1)
Production	(384.4)	(1,227.1)
Balance December 31, 2010	**6,824.4**	**39,451.9**
Developed reserves, included above		
December 31, 2008	1,394.3	2,549.5
December 31, 2009	2,055.3	4,952.5
December 31, 2010	3,720.3	18,887.7

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves and the changes in standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves were prepared in accordance with then current provisions of ASC 932 and SFAS 69. Future cash inflows at December 31, 2010 and 2009 were computed by applying the unweighted, arithmetic average on the closing price on the first day of each month for the 12-month period prior to December 31, 2010 and 2009, to estimated future production. Future cash inflows at December 31, 2008 were computed using prices in existence at that date. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year-end, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves, less the tax basis of properties involved.

Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value of our oil and natural gas properties.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	Years Ended December 31,		
	2010	2009	2008
Future cash flows	$ 709,788	$262,758	$109,100
Future production costs	(253,544)	(93,078)	(48,972)
Future development costs	(77,216)	(33,245)	(15,342)
Future income tax expense	(88,233)	(30,858)	(11,541)
Future net cash flows	290,795	105,577	33,245
10% annual discount for estimated timing of cash flows	(162,836)	(58,189)	(17,624)
Standardized measure of discounted future net cash flows	$ 127,959	$ 47,388	$ 15,621

Future cash flows as shown above were reported without consideration for the effects of commodity derivative transactions outstanding at each period end.

Changes in Standardized Measure of Discounted Future Net Cash Flows

The changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Balance, beginning of period	47,388	15,621	40,112
Net change in sales and transfer prices and in production (lifting) costs related to future production	17,133	12,387	(35,731)
Changes in estimated future development costs	(50,950)	(18,755)	(9,458)
Sales and transfers of oil and gas produced during the period	(19,054)	(4,757)	(9,107)
Net change due to extensions, discoveries and improved recovery	51,022	17,578	10,334
Net change due to revisions in quantity estimates	(355)	17,654	(4,807)
Previously estimated development costs incurred during the period	25,020	6,798	8,738
Accretion of discount	2,740	2,614	4,011
Purchase of minerals in place	112,406	8,739	—
Sale of minerals in place	(23,837)	(262)	—
Other	(1,863)	(3,606)	—
Net change in income taxes	(31,691)	(6,623)	11,529
Standardized measure of discounted future net cash flows	127,959	47,388	15,621

The commodity prices inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation are as follows.

	2010	2009	2008
Oil (per bbl)	$79.43	$54.96	$40.33
Natural gas liquids (per bbl)	$ —	$27.20	$23.00
Gas (per mcf)	$ 4.37	$ 3.35	$ 5.04

NOTE 13 — RELATED PARTY TRANSACTIONS

During 2010 and 2009, we rented an airplane for business use at various times from Pilatus Hunter, LLC, an entity 100% owned by our chairman of the board, Mr. Evans. Airplane rental expenses totaled $450,000, $161,000, and $0 for the year ended December 31, 2010, 2009, and 2008, respectively.

During 2010 and 2009, we obtained accounting services from GreenHunter Energy, Inc., an entity for which Mr. Evans is an officer and major shareholder. Professional services expenses totaled $212,000, $30,000, and $0 for the year ended December 31, 2010, 2009 and 2008, respectively.

NOTE 14 — COMMITMENTS AND CONTINGENCIES

Payable on Sale of Partnership

On September 26, 2008, the Company sold its 5.33% limited partner interest in Hall-Houston Exploration II, L. P. pursuant to a Partnership Interest Purchase Agreement dated September 26, 2008, as amended on September 29, 2008. The interest was purchased by a non-affiliated partnership for a cash consideration of $8.0 million and the purchaser's assumption of the first $1,353,000 of capital calls subsequent to September 26, 2008. The Company agreed to reimburse the purchaser for up to $754,255 of capital calls in excess of the first $1,353,000. The Company's net gain on the sale of the asset is subject to future upward adjustment to the extent that some or all of the $754,255 is not called. The liability as of December 31, 2010 and 2009 was $640,695.

Operational Contingencies

The exploration, development and production of oil and gas assets are subject to various, federal and state laws and regulations designed to protect the environment. Compliance with these regulations is part of our day-to-day operating procedures. Infrequently, accidental discharge of such materials as oil, natural gas or drilling fluids can occur and such accidents can require material expenditures to correct. We maintain levels of insurance we believe to be customary in the industry to limit its financial exposure. We are unaware of any material capital expenditures required for environmental control during this fiscal year.

Leases

As of December 31, 2010, we rent various office spaces in Houston, Texas, of approximately 22,966 square feet at a cost of $37,925 per month for remaining terms ranging from fourteen to sixty-five months. Triad had various lease commitments for periods ranging from three to eighty-three months at December 31, 2010, and with monthly payments of approximately $25,685 as of that date.

Drilling Contract

On September 25, 2010, the Company entered into a twelve month drilling contract with a third party contractor. Our maximum liability under the drilling contract, which would apply if we terminated the contract before the end of its term, is approximately $3.2 million at December 31, 2010.

Supplemental Agreements

We have outstanding employment agreements with five of our senior and executive officers for terms ranging from one to three years. Our maximum commitment under the employment agreements, which would apply if the employees covered by these agreements were all terminated without cause, was approximately $1.2 million at December 31, 2010.

NOTE 15 — CONDENSED CONSOLIDATING GUARANTOR FINANCIAL STATEMENTS

The Company and its wholly-owned subsidiaries, except Alpha Hunter Drilling, LLC, Eureka Hunter, LLC, and Hunter Real Estate, LLC, and its majority owned subsidiary, PRC Williston, LLC (collectively, "Non Guarantor Subsidiaries"), may fully and unconditionally guarantee the obligations of the Company under any debt securities that it may issue pursuant to a universal shelf registration statement, on a joint and several basis, on Form S-3. Condensed consolidating financial information for Magnum Hunter Resources Corporation and subsidiaries as of December 31, 2010 and December 31, 2009, and for the years ended December 31, 2010, 2009, and 2008 was as follows:

Magnum Hunter Resources Corporation and Subsidiaries Condensed Consolidating Balance Sheets

	As of December 31, 2010				
	Magnum Hunter Resources Corporation	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Magnum Hunter Resources Corporation Consolidated
ASSETS					
Current assets	$ 4,808,920	$ 6,436,054	$ 1,881,271	$ —	$ 13,126,245
Intercompany accounts receivable	131,690,949	—	—	(131,690,949)	—
Property and equipment (using successful efforts accounting)	12,048,947	149,647,430	70,904,248	—	232,600,625
Investment in subsidiaries	80,877,446	—	—	(80,877,446)	—
Other assets	2,723,447	511,699	4,809	—	3,239,955
Total Assets	$232,149,709	$156,595,183	$ 72,790,328	$(212,568,395)	$248,966,825
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ 24,852,489	$ 13,480,404	$ 5,902,025	$ —	$ 44,234,918
Intercompany accounts payable	—	56,326,104	75,364,845	(131,690,949)	—
Long-term liabilities	24,385,846	3,022,926	3,765,046	—	31,173,818
Redeemable preferred stock	70,236,400	—	—	—	70,236,400
Shareholders' equity	112,674,974	83,765,749	(12,241,588)	(80,877,446)	103,321,689
Total Liabilities and Stockholders' Equity	$232,149,709	$156,595,183	$ 72,790,328	$(212,568,395)	$248,966,825

	As of December 31, 2009				
	Magnum Hunter Resources Corporation	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Magnum Hunter Resources Corporation Consolidated
ASSETS					
Current assets	$ 4,755,262	$1,268,689	$ 849,307	$ —	$ 6,873,258
Intercompany accounts receivable	48,398,232	—	—	(48,398,232)	—
Property and equipment (using successful efforts accounting)	6,927,379	3,403,599	36,079,071	—	46,410,049
Investment in subsidiaries	2,684,536	—	—	(2,684,536)	—
Other assets	13,274,994	25,750	—	—	13,300,744
Total Assets	$76,040,403	$4,698,038	$ 36,928,378	$(51,082,768)	$66,584,051
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ 4,222,587	$1,507,593	$ 489,195	$ —	$ 6,219,375
Intercompany accounts payable	—	423,347	47,974,885	(48,398,232)	—
Long-term liabilities	13,874,238	131,099	1,667,664	—	15,673,001
Redeemable preferred stock	5,373,750	—	—	—	5,373,750
Shareholders' equity	52,569,828	2,635,999	(13,203,366)	(2,684,536)	39,317,925
Total Liabilities and Stockholders' Equity	$76,040,403	$4,698,038	$ 36,928,378	$(51,082,768)	$66,584,051

MAGNUM HUNTER RESOURCES CORPORATION

Notes to Financial Statements — (Continued)

Magnum Hunter Resources Corporation and Subsidiaries Condensed Consolidating Statements of Operations

	For the Twelve Months Ended December 31, 2010				
	Magnum Hunter Resources Corporation	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Magnum Hunter Resources Corporation Consolidated
Revenues	$ 1,312,437	$21,765,252	$11,983,097	$(2,337,113)	$ 32,723,673
Expenses	27,339,209	18,293,302	11,556,429	(2,337,113)	54,851,827
Loss from continuing operations before equity in net income of subsidiary	(26,026,772)	3,471,950	426,668	—	(22,128,154)
Equity in net income of subsidiary	3,770,032	—	—	(3,770,032)	—
Net income (loss)	(22,256,740)	3,471,950	426,668	(3,770,032)	(22,128,154)
Less: Net income attributable to non-controlling interest	—	—	(128,586)	—	(128,586)
Net income (loss) from continuing operations attributable to Magnum Hunter Resources Corporation	(22,256,740)	3,471,950	298,082	(3,770,032)	(22,256,740)
Income from discontinued operations	8,456,811	—	—	—	8,456,811
Net loss	(13,799,929)	3,471,950	298,082	(3,770,032)	(13,799,929)
Dividends on preferred stock	2,466,679	—	—	—	2,466,679
Net income (loss) attributable to common shareholders	$(16,266,608)	$ 3,471,950	$ 298,082	$(3,770,032)	$(16,266,608)

	For the Twelve Months Ended December 31, 2009				
	Magnum Hunter Resources Corporation	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Magnum Hunter Resources Corporation Consolidated
Revenues	$ 981,460	$103,238	$5,776,804	$ (17,933)	$ 6,843,569
Expenses	16,054,229	151,775	6,282,052	(11,907)	22,476,149
Loss from continuing operations before equity in net losses of subsidiary	(15,072,769)	(48,537)	(505,248)	(6,026)	(15,632,580)
Equity in net loss of subsidiary	(490,629)	—	—	490,629	—
Net loss	(15,563,398)	(48,537)	(505,248)	484,603	(15,632,580)
Less: Net loss attributable to non-controlling interest	—	—	63,156	—	63,156
Net loss from continuing operations attributable to Magnum Hunter Resources Corporation	(15,563,398)	(48,537)	(442,092)	484,603	(15,569,424)
Income from discontinued operations	445,215	—	—	—	445,215
Net loss	(15,118,183)	(48,537)	(442,092)	484,603	(15,124,209)
Dividends on preferred stock	25,654	—	—	—	25,654
Net loss attributable to common shareholders	$(15,143,837)	$ (48,537)	$ (442,092)	$484,603	$(15,149,863)

	For the Twelve Months Ended December 31, 2008				
	Magnum Hunter Resources Corporation	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Magnum Hunter Resources Corporation Consolidated
Revenues	$ 1,629,303	$—	$ 9,960,478	$ —	$ 11,589,781
Expenses	(385,601)	—	23,084,203	—	22,698,602
Income (loss) from continuing operations before equity in net losses of subsidiary	2,014,904	—	(13,123,725)	—	(11,108,821)
Equity in net loss of subsidiary	(11,483,259)	—	—	11,483,259	—
Net loss	(9,468,355)	—	(13,123,725)	11,483,259	(11,108,821)
Less: Net loss attributable to non-controlling interest	—	—	1,640,466	—	1,640,466
Net loss from continuing operations attributable to Magnum Hunter Resources Corporation	(9,468,355)	—	(11,483,259)	11,483,259	(9,468,355)
Income from discontinued operations	2,582,021	—	—	—	2,582,021
Net loss	(6,886,334)	—	(11,483,259)	11,483,259	(6,886,334)
Dividends on preferred stock	734,406	—	—	—	734,406
Net loss attributable to common shareholders	$ (7,620,740)	$—	$(11,483,259)	$11,483,259	$ (7,620,740)

Magnum Hunter Resources Corporation and Subsidiaries Condensed Consolidating Statements of Cash Flows

	For the Year Ended December 31, 2010				
	Magnum Hunter Resources Corporation	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Magnum Hunter Resources Corporation Consolidated
Cash flow from operating activities	$ (92,809,146)	$ 72,453,047	$ 19,189,232	$—	$ (1,166,867)
Cash flow from investing activities	(21,925,836)	(77,193,571)	(19,161,326)	—	(118,280,733)
Cash flow from financing activities	117,998,360	(79,723)	(198,419)	—	117,720,218
Net increase (decrease) in cash	3,263,378	(4,820,247)	(170,513)	—	(1,727,382)
Cash at beginning of period	(1,707,061)	3,726,562	262,067	—	2,281,568
Cash at end of period	$ 1,556,317	$ (1,093,685)	$ 91,554	$—	$ 554,186

	For the Year Ended December 31, 2009				
	Magnum Hunter Resources Corporation	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Magnum Hunter Resources Corporation Consolidated
Cash flow from operating activities	$ 718,543	$ 439,018	$ 2,214,178	$—	$ 3,371,739
Cash flow from investing activities	(12,548,538)	(529,064)	(3,546,016)	—	(16,623,618)
Cash flow from financing activities	9,413,045	—	—	—	9,413,045
Net decrease in cash	(2,416,950)	(90,046)	(1,331,838)	—	(3,838,834)
Cash at beginning of period	4,420,499	235,022	1,464,881	—	6,120,402
Cash at end of period	$ 2,003,549	$ 144,976	$ 133,043	$—	$ 2,281,568

	For the Year Ended December 31, 2008				
	Magnum Hunter Resources Corporation	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Magnum Hunter Resources Corporation Consolidated
Cash flow from operating activities	$ 1,091,868	$—	$ 2,345,461	$—	$ 3,437,329
Cash flow from investing activities	(8,196,187)	—	(2,182,441)	—	(10,378,628)
Cash flow from financing activities	(2,337,846)	—	—	—	(2,337,846)
Net increase (decrease) in cash	(9,442,165)	—	163,020	—	(9,279,145)
Cash at beginning of period	14,097,686	—	1,301,861	—	15,399,547
Cash at end of period	$ 4,655,521	$—	$ 1,464,881	$—	$ 6,120,402

NOTE 16 — SUBSEQUENT EVENTS

We sold an additional 1,280,278 shares of our Series C Perpetual Preferred Stock at a price of $25.00 per share, for net proceeds of approximately $32.0 million, pursuant to our ATM sales agreement subsequent to December 31, 2010 through the date of this report. There are a total of 4,000,000 shares of Series C Preferred Stock outstanding at the date of this report.

The Company issued 245,000 shares of the Company's common stock upon the exercise of 240,000 of our $3.00 common stock warrants and 3,048 of our $2.50 common stock warrants for total proceeds of $735,000, subsequent to December 31, 2010 through the date of this report.

The Company issued 329,680 shares of common stock upon the exercise of 329,680 of common stock options and for total proceeds of $1.3 million subsequent to December 31, 2010 through the date of this report.

NGAS

On December 23, 2010, the Company and NGAS Resources, Inc., a British Columbia corporation ("*NGAS*"), entered into an Arrangement Agreement ("Arrangement Agreement"), pursuant to which the Company will acquire all of the issued and outstanding equity of NGAS. The proposed transaction will be implemented by way of a court-approved plan of arrangement under British Columbia law. Under the proposed transaction, each common share of NGAS will be transferred to the Company for the right to receive 0.0846 shares of the Company's common stock. The exchange ratio for the proposed transaction was established based on an agreed stock price of the Company of $6.50, representing a value to NGAS' shareholders of $0.55 per share. The exchange ratio will not be adjusted for subsequent changes in market prices of the Company's or NGAS' common stock prior to the closing of the proposed transaction.

The closing of the transaction is subject to various conditions, including, among others: (i) the approval of the Arrangement Agreement and the proposed transaction by two-thirds of the votes cast by NGAS' shareholders present in person or represented by proxy at NGAS' special meeting of shareholders, (ii) the receipt of an interim and final order from the Supreme Court of British Columbia pursuant to Section 291 of the Business Corporation Act (British Columbia), (iii) in the case of NGAS' obligation to close, the full payment of all outstanding amounts owed by NGAS under its existing credit agreement and the full payment of the NGAS 6% amortizing convertible notes that have not been converted into NGAS common shares before the Closing, (iv) in the case of the Company's obligation to close, (a) the entry into a definitive agreement with a third party to restructure an "out-of-market" gas gathering and transportation agreement on substantially the terms set forth in a letter of intent between the

Company, NGAS and such third party, (b) the reduction of change of control, severance and retention benefits payable to NGAS' officers and employees to an amount not to exceed $5,000,000, and (c) no amendment or rescission prior to the Closing of the fairness opinion delivered to NGAS by NGAS' financial advisor, (v) the absence of injunctions or restraints imposed by governmental entities, (vi) the accuracy of the representations and warranties of the other party and (vii) compliance by the other party with its obligations under the Arrangement Agreement. In connection with the condition relating to the restructuring of the "out-of-market" gas gathering and transportation agreement, the letter of intent provides that (i) the Company would pay $10 million in cash or restricted shares of the Company's common stock to the third party referred to above and provide such third party with the right to acquire a 50% interest in the Company's Marcellus gas processing plant, and (ii) NGAS would cancel approximately $7 million in note installments from the third party's purchase of NGAS' Appalachian gathering system in August 2009. The Closing is currently expected to occur in the first quarter of 2011.

The Arrangement Agreement includes customary representations, warranties and covenants by the parties, including among other things a "no-solicitation" covenant that restricts NGAS' ability to solicit third party proposals relating to alternative transactions or to provide information or enter into discussions in connection with alternative transactions, subject to certain limited exceptions to permit NGAS' Board of Directors to comply with its fiduciary duties. The Arrangement Agreement also contains a covenant that NGAS will use its reasonable best efforts to extend the deadline for completing a qualifying transaction under its previously reported credit agreement waiver and amendment from March 31, 2011 to April 15, 2011, the extension date.

The Arrangement Agreement contains certain termination rights for both the Company and NGAS, including if (a) a governmental entity issues an order prohibiting the consummation of the transactions contemplated by the Arrangement Agreement, (b) the closing of the transaction has not occurred on or before March 31, 2011 or the extension date of April 15, 2011, or (c) NGAS' shareholders do not approve the terms of the Arrangement Agreement and the proposed transaction. The Arrangement Agreement provides that the Company will be entitled to a termination fee of $4,000,000 if the Arrangement Agreement is terminated upon certain specified events, including in the event NGAS accepts a "Superior Proposal" (as defined in the Arrangement Agreement) or a change in recommendation of NGAS' Board of Directors, which could result from, among other things, an "Intervening Event" (as defined in the Arrangement Agreement). If the Arrangement Agreement is terminated due to a failure of NGAS' shareholders to approve the proposed transaction, NGAS will reimburse the Company for all of its reasonable expenses incurred in connection with the proposed transaction up to $4,000,000.

On January 13, 2011 we have signed a commitment letter with Bank of Montreal for a five-year senior secured revolving loan of up to $250 million with an initial borrowing base availability of up to $145 million conditional upon the closing of the NGAS acquisition and NuLoch acquisitions.

On January 14, 2011, we closed the second phase of the PostRock acquisition, the Lewis County assets, for total consideration of approximately $13.3 million which consisted of 946,314 shares of the Company's restricted common stock and a cash payment of approximately $5.8 million.

The following table summarizes the purchase price and the fair values of the net assets acquired as of January 14, 2011:

Fair value of total purchase price:	
946,314 shares of common stock issued on January 14, 2011 at $7.97 per share	$ 7,542,122
Cash paid on January 14, 2011	5,763,983
Total	$13,306,105
Amounts recognized for assets acquired and liabilities assumed:	
Working capital	$ (23,184)
Oil and gas properties	13,342,539
Equipment and other fixed assets	3,750
Asset retirement obligation	(17,000)
Total	$13,306,105
Working capital acquired	
Prepaid expenses	$ 2,658
Transfer tax payable	(25,842)
	$ (23,184)

On January 19, 2011, the Company, MHR ExchangeCo Corporation, a newly-formed corporation existing under the laws of the Province of Alberta and an indirect wholly owned subsidiary of the Company ("ExchangeCo"), and NuLoch Resources Inc., a corporation existing under the laws of the Province of Alberta ("NuLoch"), entered into an Arrangement Agreement, dated as of January 19, 2011 (the "Arrangement Agreement"), pursuant to which the Company through ExchangeCo will acquire all of the issued and outstanding equity of NuLoch. The proposed transaction will involve an exchange of NuLoch's Class A common shares (the "NuLoch Shares") to the Company for shares of the Company's common stock (the "MHR Shares") and exchangeable shares of ExchangeCo (the "Exchangeable Shares"), as described below. The proposed transaction will be implemented by way of the plan of arrangement attached as Exhibit B to the Arrangement Agreement (the "Plan of Arrangement") and is subject to court approval under Alberta law.

Pursuant to the Arrangement Agreement and Plan of Arrangement, holders of NuLoch Shares who are residents of Canada will receive, at the holder's election, (1) a number of Exchangeable Shares equal to the number of NuLoch Shares so exchanged multiplied by the Exchange Ratio (as defined below), (2) a number of MHR Shares equal to the number of NuLoch Shares so exchanged multiplied by the Exchange Ratio, or (3) a combination of Exchangeable Shares and MHR Shares as described in clauses (1) and (2) above. Holders of NuLoch Shares who are non-Canadian residents will receive a number of MHR Shares equal to the number of NuLoch Shares so exchanged multiplied by the Exchange Ratio. The Exchange Ratio of 0.3304, was calculated based on an agreed to value of CAD $2.50 per NuLoch Share which was divided by the volume weighted average price of the Company's common stock for the seven-day period ending on (and including) the date immediately prior to the date the Arrangement Agreement was executed, or $7.63 per share (as adjusted to account for applicable currency exchange rates). The Exchange Ratio will not be adjusted for any subsequent changes in market prices of the MHR Shares or NuLoch Shares prior to the closing of the proposed transaction. The Exchangeable Shares will be exchangeable into MHR Shares (on a share-for-share basis) and will carry voting and divided/distribution rights which are designed to put holders of the Exchangeable Shares in the same functional and economic position as holders of MHR Shares. Any Exchangeable Shares not previously exchanged will be automatically exchanged for MHR Shares on the date that is the one year anniversary of the closing date of the proposed transaction, subject to applicable law, unless the Company exchanges them earlier upon the occurrence of certain events.

The closing of the proposed transaction (the "Closing") is subject to various conditions, including, among others: (1) the approval of NuLoch's shareholders and NuLoch optionholders with respect to the adoption of the Plan of Arrangement (the "NuLoch Securityholder Approval"), (2) the approval of the Company's stockholders with respect to the issuance of MHR Shares (including the issuance of MHR Shares upon exchange of the Exchangeable Shares) as consideration for the proposed transaction (the "Company Stockholder Approval"), in accordance with the rules of the New York Stock Exchange (the "NYSE"), (3) the approval of the Court of Queen's Bench of Alberta (the "Court"), (4) holders of not more than five percent of the outstanding NuLoch Shares and NuLoch stock options exercising rights of dissent in respect to the Plan of Agreement, (5) the Closing occurring on or before May 31, 2011, (6) the MHR Shares (including the MHR Shares issuable upon exchange of the Exchangeable Shares) issued as consideration are authorized for listing on the NYSE and are generally freely tradeable without further registration under applicable securities laws of the U.S. and Canada, subject, with respect to the MHR Shares issuable upon exchange of the Exchangeable Shares, to the effectiveness of a registration statement on Form S-3 covering such exchange (the "Registration Statement"), (7) the fairness opinion of NuLoch's financial advisor has not been amended or rescinded, and (8) other conditions customary for a transaction of this nature. The Closing is currently expected to occur in the second quarter of 2011.

The Arrangement Agreement includes customary representations, warranties and covenants by the parties, including, among other things, a "non-solicitation" covenant that restricts NuLoch's ability to solicit third party proposals relating to alternative transactions or to provide information or enter into discussions in connection with alternative transactions, subject to certain limited exceptions to permit NuLoch's Board of Directors to comply with its fiduciary duties. The Arrangement Agreement also contains a covenant that the Company will use all reasonable best efforts to file the Registration Statement with the Securities and Exchange Commission (the "SEC") in order to register the MHR Shares issuable upon exchange of the Exchangeable Shares, cause such Registration Statement to become effective, and maintain its effectiveness for so long as any Exchangeable Shares remain outstanding.

The Arrangement Agreement contains certain termination rights for both the Company and NuLoch, including if a governmental entity denies granting a requisite regulatory approval or takes action prohibiting the proposed transaction, the Closing has not occurred on or before May 31, 2011, the NuLoch Securityholder Approval is not obtained or the Company Stockholder Approval is not obtained. In addition, the Company may terminate the Arrangement Agreement if (1) the NuLoch Board of Directors changes its recommendation that the NuLoch Securityholders approve the proposed transaction, which could result from an "Intervening Event" or "Superior Proposal" (both as defined in the Arrangement Agreement), (2) an acquisition proposal is made to NuLoch or its shareholders and the NuLoch Securityholder Approval is not obtained, (3) NuLoch recommends or enters into a Superior Proposal (as defined in the Arrangement Agreement), or (4) NuLoch breaches its non-solicitation covenant. NuLoch may terminate the Arrangement Agreement if it has received a Superior Proposal; *provided* that it has complied with the required terms and conditions with respect to such proposal, which include, among other things, providing the Company with notice of and the right to match such Superior Proposal.

Pursuant to the Arrangement Agreement, the Company will be entitled to a termination fee of U.S. $10 million if the Arrangement Agreement is terminated upon certain specified events, including (1) NuLoch recommends or accepts a Superior Proposal, (2) the NuLoch Board of Directors changes its recommendation that the NuLoch Securityholders approve the proposed transaction, (3) an acquisition proposal is made to NuLoch or its shareholders, the NuLoch Securityholder Approval is not obtained, and either (i) such acquisition proposal, or any other acquisition proposal that is announced prior to termination, is consummated within 12 months of the date of the first acquisition proposal or (ii) any other acquisition proposal that is announced after termination is consummated by September 30, 2011, or (4) NuLoch breaches and fails to cure its non-solicitation covenant. In addition, if the NuLoch Securityholder Approval has not been obtained and none of the termination circumstances listed above exist, in the event of the termination of the Arrangement Agreement, NuLoch will be required to pay the Company its reasonable expenses incurred with respect to the proposed transaction, subject to a cap of U.S. $3 million. If the Company Stockholder Approval has not been obtained and none of the termination circumstances listed above exist, in the event of the termination of the Arrangement Agreement, the Company will be required to pay NuLoch its reasonable expenses incurred with respect to the proposed transaction, subject to a cap of U.S. $3 million.

Concurrently, and in connection with entering into the Arrangement Agreement, the Company and certain securityholders of NuLoch entered into support agreements, in substantially the form attached as Exhibit A to the Arrangement Agreement (collectively, the "Support Agreements"), pursuant to which, subject to the conditions set forth therein, such securityholders have agreed to, among other things, to vote all securities of NuLoch beneficially owned by them, as well as any additional securities which they may acquire or own, in favor of the proposed transaction described above and all matters related thereto. In addition, such securityholders have agreed to substantially similar non-solicitation restrictions as those imposed upon NuLoch pursuant to the Arrangement Agreement. The Support Agreements can be terminated by the securityholder if the consideration payable to the securityholder is reduced or changed or if the Arrangement Agreement is terminated. Support Agreements were signed by all directors, executive officers and certain employees of NuLoch. In addition, certain institutional shareholders of NuLoch signed a support agreement that differs in form from the Support Agreement primarily in that the agreement is also terminable by the shareholder in the event NuLoch receives a Superior Proposal that is not matched by the Company within three business days of the Company's receipt of notice of the Superior Proposal.

Item 9. *CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE*

None.

Item 9A. *CONTROLS AND PROCEDURES*

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) was performed under the supervision and with the participation of the Company's management, including our Chief Executive Officer and Chief Financial Officer. Based on that evaluation, the Company's Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2010 to ensure: that information required to be disclosed in the reports it files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms; and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to the Company's management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Evaluation of Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have determined that, during the fourth quarter of fiscal 2010, there were no changes in our internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Management's Report on Internal Controls over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we assessed the effectiveness of our internal controls over financial reporting as of the end of the period covered by this report based on the framework in "Internal Control — Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, our Chief Executive Officer and Chief Financial Officer concluded that our internal controls over financial reporting were effective as of December 31, 2010 to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

The effectiveness of the Company's internal controls over financial reporting as of December 31, 2010, has been audited by Hein & Associates, LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Important Considerations

The effectiveness of our disclosure controls and procedures and our internal controls over financial reporting is subject to various inherent limitations, including cost limitations, judgments used in decision making, assumptions about the likelihood of future events, the soundness of our systems, the possibility of human error, and the risk of fraud. Moreover, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions and the risk that the degree of compliance with policies or procedures may deteriorate over time. Because of these limitations, there can be no assurance that any system of disclosure controls and procedures or internal controls over financial reporting will be successful in preventing all errors or fraud or in making all material information known in a timely manner to the appropriate levels of management.

Item 9B. *OTHER INFORMATION*

None

PART III

Item 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

Information as to Item 10 will be set forth in the Proxy Statement ("Proxy Statement") for the Company's Annual Meeting of Stockholders anticipated to be held in April 2011 ("Annual Meeting") and is incorporated herein by reference.

Item 11. *EXECUTIVE COMPENSATION*

Information as to Item 11 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

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

Information as to Item 12 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 13. *CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE*

Information as to Item 13 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 14. *PRINCIPAL ACCOUNTANT FEES AND SERVICES*

Information as to Item 14 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

PART IV

Item 15. *EXHIBITS, FINANCIAL STATEMENT SCHEDULES.*

(a) 1. *Consolidated Financial Statements:* See Index to Financial Statements on page F-1.

2. *Financial Statement Schedule:* We have included on page 82 of this annual report on Form 10-K, Financial Statement Schedule II, Valuation and Qualifying Accounts

3. *Exhibits:* The exhibits listed below are filed or incorporated by reference as part of the annual report.

Exhibit Number	Description
3.1(1)	Restated Certificate of Incorporation of the Registrant, filed February 13, 2002
3.1.1(1)	Certificate of Amendment of Certificate of Incorporation of the Registrant, filed May 8, 2003
3.1.2(1)	Certificate of Amendment of Certificate of Incorporation of the Registrant, filed June 6, 2005
3.1.3(4)	Certificate of Amendment of Certificate of Incorporation of the Registrant, filed July 18, 2007
3.1.4(7)	Certificate of Ownership and Merger Merging Magnum Hunter Resources Corporation with and into Petro Resources Corporation, filed July 13, 2009
3.1.5(22)	Certificate of Amendment of Certificate of Incorporation of the Registrant, filed November 3, 2010
3.2(1)	Amended and Restated Bylaws of the Registrant, dated March 15, 2001
3.2.1(2)	Amendment to Bylaws of the Registrant, dated April 14, 2006

Exhibit Number	Description
3.2.2(5)	Amendment to Bylaws of the Registrant, dated October 12, 2006
4.1	Form of certificate for common stock#
4.2(13)	Certificate of Designation of Rights and Preferences of 10.25% Series C Cumulative Perpetual Preferred Stock, dated December 10, 2009
4.2.1(16)	Certificate of Amendment of Certificate of Designation of Rights and Preferences of 10.25% Series C Cumulative Perpetual Preferred Stock, dated August 2, 2010
4.2.2(20)	Certificate of Amendment of Certificate of Designation of Rights and Preferences of 10.25% Series C Cumulative Perpetual Preferred Stock, dated September 8, 2010
10.1(15)	Employment Agreement between the Registrant and James W. Denny, dated May 27, 2008*
10.2(6)	Employment Agreement between the Registrant and Gary C. Evans, dated May 22, 2009*
10.3(6)	Stock Option Agreement between the Registrant and Gary C. Evans, dated May 22, 2009*
10.4(6)	Restricted Stock Agreement between the Registrant and Gary C. Evans, dated May 22, 2009*
10.5(6)	Employment Agreement between the Registrant and Ronald D. Ormand, dated May 22, 2009*
10.6(6)	Stock Option Agreement between the Registrant and Ronald D. Ormand, dated May 22, 2009*
10.7(6)	Restricted Stock Agreement between the Registrant and Ronald D. Ormand, dated May 22, 2009*
10.8	Employment Agreement between the Registrant and H.C. "Kip" Ferguson, dated October 1, 2009*#
10.9	Resignation and General Release Agreement between the Registrant and Wayne P. Hall, dated December 22, 2010#
10.10(25)	Amended and Restated Stock Incentive Plan of Registrant*
10.11	Form of Stock Option Agreement under the Registrant's Amended and Restated Stock Incentive Plan*#
10.12(25)	Form of Restricted Stock Award Agreement under the Registrant's Amended and Restated Stock Incentive Plan*
10.13(25)	Form of Stock Appreciation Right Agreement under the Registrant's Amended and Restated Stock Incentive Plan*
10.14(1)	Lease Purchase Agreement between the Registrant and The Meridian Resource & Exploration, LLC, dated January 10, 2006
10.15(1)	Form of Registration Rights Agreement for $3.00 warrants sold as part of the Registrant's February 2006 private placement, dated February 17, 2006
10.16(1)	Form of $3.00 Warrant sold as part of February 2006 private placement
10.17(3)	Purchase and Sale Agreement between the Registrant and Eagle Operating, Inc., dated December 11, 2006
10.18	First Amendment to Purchase and Sale Agreement between the Registrant and Eagle Operating, Inc., dated January 25, 2007#
10.19(8)	Agreement and Plan of Merger between the Registrant, Sharon Hunter, Inc., Sharon Resources, Inc. and Sharon Energy Ltd., dated September 9, 2009
10.20(8)	Purchase and Sale Agreement between the Registrant and Centurion Exploration Company, LLC, dated September 14, 2009
10.21(9)	Asset Purchase Agreement between the Registrant and Triad Energy Corporation, dated October 28, 2009
10.22(10)	Form of Securities Purchase and Registration Rights Agreement with respect to November 5, 2009 offering
10.23(10)	Form of $2.50 Warrant with respect to the Registrant's November 5, 2009 offering
10.24(11)	Placement Agency Agreement with respect to the Registrant's November 10, 2009 offering, dated November 10, 2009
10.25(11)	Placement Agency Agreement with respect to the Registrant's November 11, 2009 offering, dated November 11, 2009
10.26(11)	Form of $2.50 Warrant with respect to the Registrant's November 10 and 11, 2009 offerings

Exhibit Number	Description
10.27(12)	Underwriting Agreement between the Registrant and Wunderlich Securities, Inc., dated December 9, 2009
10.28(14)	Amended and Restated Credit Agreement between the Registrant, Bank of Montreal, Capital One, N.A., BMO Capital Markets and Capital One, N.A and the lenders party thereto, dated February 12, 2010+
10.29(17)	First Amendment to Amended and Restated Credit Agreement between the Registrant, Bank of Montreal, Capital One, N.A., and the lenders party thereto, dated May 13, 2010
10.30(18)	At the Market Sales Agreement for Series C Preferred Stock between the Registrant and McNicoll, Lewis & Vlak LLC, dated June 22, 2010
10.31(19)	At the Market Sales Agreement for common stock between the Registrant and McNicoll, Lewis & Vlak LLC, dated June 25, 2010
10.32(21)	Limited Waiver of Credit Agreement Provisions, between the Registrant and Bank of Montreal and Capital One, N.A., dated September 24, 2010
10.33(23)	Purchase and Sale Agreement between the Registrant and Approach Oil & Gas Inc., dated October 29, 2010+
10.34(24)	At the Market Sales Agreement for common stock between the Registrant and McNicoll, Lewis and Vlak, LLC, dated November 12, 2010
10.35(24)	At the Market Sales Agreement for Series C Preferred Stock between the Registrant and McNicoll, Lewis and Vlak, LLC, dated November 12, 2010
10.36(26)	Second Amendment to Amended and Restated Credit Agreement and Waiver between the Registrant, Bank of Montreal, Capital One, N.A., and the guarantors and lenders party thereto, dated November 30, 2010+
10.37(27)	Arrangement Agreement between the Registrant and NGAS Resources, Inc., dated December 23, 2010+
10.38(27)	Form of Support Agreement between the Registrant and certain NGAS Resources, Inc. shareholders, dated December 23, 2010
10.39(28)	Purchase and Sale Agreement between the Registrant, Quest Eastern Resource LLC and PostRock MidContinent Production, LLC, dated December 24, 2010+@
10.40(29)	Arrangement Agreement between the Registrant and NuLoch Resources Inc., dated January 19, 2011(including Form of Support Agreement between the Registrant and certain NuLoch Resources Inc. shareholders)+
21.1	List of Subsidiaries#
23.1	Consent of Hein & Associates LLP#
23.2	Consent of MaloneBailey, LLP#
23.3	Consent of Cawley Gillespie & Associates, Inc#
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002#
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002#
32.1	Certification of the Chief Executive Officer and Chief Financial Officer provided pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002#
99.1	Independent Engineer Reserve Report for the year ended December 31, 2010 prepared by Cawley Gillespie & Associates, Inc.#

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* The referenced exhibit is a management contract, compensatory plan or arrangement.

\+ The schedules to this exhibit have been omitted pursuant to Item 601(b)(2) of Regulation S-K and will be provided to the SEC upon request.

@ Portions of this exhibit are subject to a request for confidential treatment and have been redacted and filed separately with the SEC.

\# Filed Herewith

(1) Incorporated by reference from the Registrant's Registration Statement on Form SB-2 filed on March 21, 2006.

(2) Incorporated by reference from the Registrant's Amendment No. 1 to Registration Statement on Form SB-2 filed on June 9, 2006.

(3) Incorporated by reference from the Registrant's annual report on Form 10-KSB for the year ended December 31, 2006, filed on April 2, 2007.

(4) Incorporated by reference from the Registrant's quarterly report on Form 10-QSB filed on August 14, 2007.

(5) Incorporated by reference from the Registrant's Amendment No. 1 to Registration Statement on Form SB-2 filed on September 21, 2007.

(6) Incorporated by reference from the Registrant's current report on Form 8-K filed on May 28, 2009.

(7) Incorporated by reference from the Registrant's current report on Form 8-K filed on July 14, 2009.

(8) Incorporated by reference from the Registrant's current report on Form 8-K filed on September 15, 2009.

(9) Incorporated by reference from the Registrant's current report on Form 8-K filed on October 29, 2009.

(10) Incorporated by reference from the Registrant's current report on Form 8-K filed on November 6, 2009.

(11) Incorporated by reference from the Registrant's current report on Form 8-K filed on November 13, 2009.

(12) Incorporated by reference from the Registrant's current report on Form 8-K filed on December 11, 2009.

(13) Incorporated by reference from the Registrant's Registration Statement on Form 8-A filed on December 10, 2009.

(14) Incorporated by reference from the Registrant's current report on Form 8-K filed on February 19, 2010.

(15) Incorporated by reference from the Registrant's annual report on Form 10-K filed on March 31, 2009.

(16) Incorporated by reference from the Registrant's quarterly report on Form 10-Q filed on August 12, 2010.

(17) Incorporated by reference from the Registrant's current report on Form 8-K filed on May 19, 2010.

(18) Incorporated by reference from the Registrant's current report on Form 8-K filed on June 24, 2010.

(19) Incorporated by reference from the Registrant's current report on Form 8-K filed on June 25, 2010.

(20) Incorporated by reference from the Registrant's current report on Form 8-K filed on September 15, 2010.

(21) Incorporated by reference from the Registrant's current report on Form 8-K filed on September 30, 2010.

(22) Incorporated by reference from the Registrant's current report on Form 8-K filed on November 2, 2010.

(23) Incorporated by reference from the Registrant's current report on Form 8-K filed on November 4, 2010.

(24) Incorporated by reference from the Registrant's current report on Form 8-K filed on November 15, 2010.

(25) Incorporated by reference from the Registrant's current report on Form 8-K filed on December 3, 2010.

(26) Incorporated by reference from the Registrant's current report on Form 8-K filed on December 6, 2010.

(27) Incorporated by reference from the Registrant's current report on Form 8-K filed on December 30, 2010.

(28) Incorporated by reference from the Registrant's current report on Form 8-K filed on January 5, 2011.

(29) Incorporated by reference from the Registrant's current report on Form 8-K filed on January 25, 2011.

PART II — OTHER INFORMATION

MAGNUM HUNTER RESOURCES CORPORATION
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEAR ENDED DECEMBER 31, 2010

(in thousands)

Classification	Balance at Beginning of Year	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Year
Year Ended December 31, 2010					
Allowance for doubtful accounts on Trade Accounts Receivable	—	213	—	—	213

SIGNATURES

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

MAGNUM HUNTER RESOURCES CORPORATION

By: /s/ Gary C. Evans

Gary C. Evans
Chairman of the Board and Chief Executive Officer

Date: February 17, 2011

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

Signature	Title	Date
/s/ Gary C. Evans Gary C. Evans	Chairman of the Board and Chief Executive Officer (Principal Executive Officer)	February 17, 2011
/s/ Ronald D. Ormand Ronald D. Ormand	Executive Vice President, Chief Financial Officer and Director (Principal Financial Officer)	February 17, 2011
/s/ David S. Krueger David S. Krueger	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 17, 2011
/s/ J. Raleigh Bailes, Sr. J. Raleigh Bailes, Sr.	Director	February 17, 2011
/s/ Brad Bynum Brad Bynum	Director	February 17, 2011
/s/ Victor Carrillo Victor Carrillo	Director	February 17, 2011
/s/ Gary L. Hall Gary L. Hall	Director	February 17, 2011
/s/ Joe L. McClaugherty Joe L. McClaugherty	Director	February 17, 2011
/s/ Steven A. Pfeifer Steven A. Pfeifer	Director	February 17, 2011
/s/ Jeff Swanson Jeff Swanson	Director	February 17, 2011

Corporate and Investor Information

Corporate Officers

Gary C. Evans
Chairman of the Board and Chief Executive Officer

Jim Denny
Executive Vice President of Operations and
President of Triad Hunter, LLC

H.C. "Kip" Ferguson, III
Executive Vice President of Exploration

Ronald D. Ormand
Executive Vice President and Chief Financial Officer

Brian Burgher
Senior Vice President of Land

M. Bradley Davis
Senior Vice President of Capital Markets

Richard S. Farrell
Senior Vice President of Business Development and Land,
Triad Hunter, LLC

Paul M. Johnston
Senior Vice President and General Counsel

Don Kirkendall
Senior Vice President – Director of Product Marketing
and Administration, Eureka Hunter Pipeline

David S. Krueger
Senior Vice President and Chief Accounting Officer

Dan McCormick
Senior Vice President of Operations, Eureka Hunter Pipeline

Kirk Trosclair
Senior Vice President of Equipment Services,
Triad Hunter, LLC

Debbie Funderburg
Vice President of Reservoir Engineering

David Lipp
Vice President of Business Development and Legal

Victor Ponce de Leon
Vice President of Finance and Treasurer

Board of Directors

Gary C. Evans
Chairman of the Board and Chief Executive Officer

J. Raleigh Bailes, C.P.A.
Bailes Bates & Associates, LLP

Brad Bynum
Chief Financial Officer of Hall-Houston
Exploration Partners, L.L.C.

Victor G. Carrillo
Former Chairman of the Texas Railroad Commission
and Executive Vice President of Zion Oil & Gas, Inc.

Gary L. Hall
President of Hall-Houston Exploration Partners, L.L.C.

Joe L. McClaugherty
Senior Partner of McClaugherty & Silver, P.C.

Ronald D. Ormand
Executive Vice President and Chief Financial Officer

Steven Pfeifer
Managing Member of P.O.&G. Resources –
Texas, L.L.C.

Jeff Swanson
President and Chief Executive Officer of GrailQuest
Corporation and Durango Resources Corporation

Corporate Headquarters
Magnum Hunter Resources
777 Post Oak Blvd., Suite 650
Houston, TX 77056
Telephone: (832) 369-6986
Fax: (832) 369-6992
Website: http://www.magnumhunterresources.com

Principal Subsidiaries
Alpha Hunter Drilling, LLC
Eureka Hunter Pipeline, LLC
Hunter Disposal, LLC
Hunter Real Estate, LLC
PRC Williston, LLC
Sharon Hunter Resources, Inc.
Triad Hunter, LLC

Independent Auditors
Hein & Associates, LLP

Independent Reservoir Engineers
Cawley Gillespie & Associates, Inc.

Independent Counsel
Fulbright & Jaworski, LLP

Transfer Agent
American Stock Transfer & Trust Co., LLC
6201 15th Avenue
Brooklyn, NY 11219
Telephone: (800) 937-5449
Fax: (718) 236-2641

Common Stock
Magnum Hunter Resources common stock trades on the NYSE under the symbol "MHR." The following table shows the quarterly high and low sales price per share and the average daily trading volume for the common stock for the periods indicated.

2010	High	Low	Average Daily Trading Volume
First Quarter	$ 3.29	$ 1.50	599,550
Second Quarter	$ 5.49	$ 3.00	1,041,185
Third Quarter	$ 4.85	$ 3.75	456,428
Fourth Quarter	$ 8.05	$ 3.87	1,057,689

Preferred Stock
Magnum Hunter Resources Series "C" preferred stock trades on the NYSE Amex under the symbol "MHR-PrC."

Magnum Hunter Resources Series "D" preferred stock trades on the NYSE Amex under the ticker symbol "MHR-PrD"

Contact
M. Bradley Davis – Senior Vice President of Capital Markets
Telephone: (832) 203-4545
Bdavis@magnumhunterresources.com

MAGNUM HUNTER
RESOURCES CORPORATION

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Houston, TX 77056
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