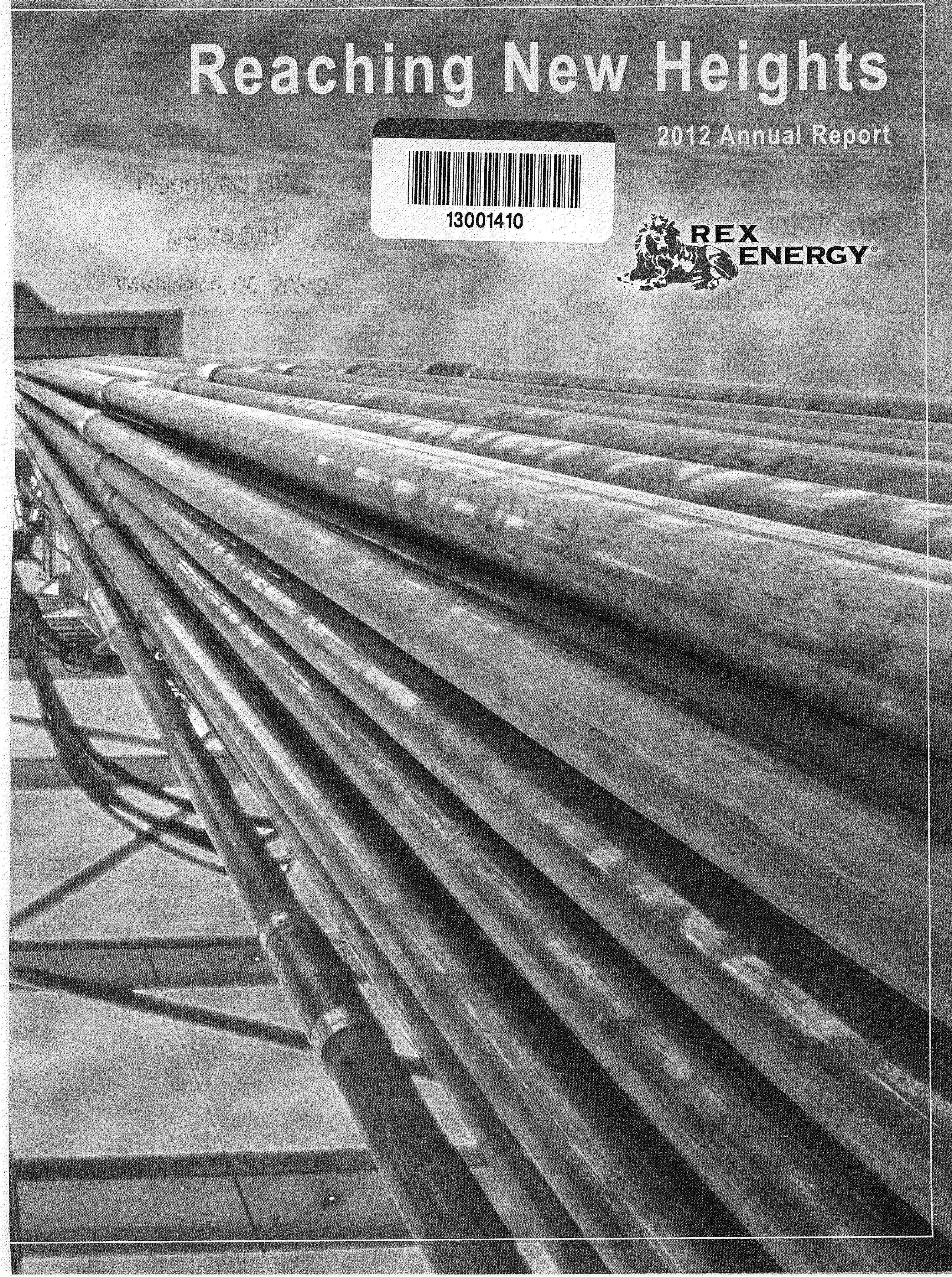
Reaching New Heights

2012 Annual Report

REX ENERGY®



COMMIT • EXECUTE • DELIVER

DEAR FELLOW SHAREHOLDERS

As I pause for a moment to reflect upon 2012, one word consistently resonates through each of our accomplishments for the year: Execution. 2012 was a year of strong execution for Rex Energy. In my letter to you last year, I outlined our priorities for 2012 and set some very explicit goals for our company for the year. I am pleased to report that we successfully executed the strategies we laid out to achieve those goals. We focused on operational excellence within our core asset, our Butler Operated Area, increasing the EURs of our Marcellus locations and decreasing both drilling and operating costs per unit. We added valuable incremental acreage to our Ohio Utica Shale position where we initiated an exploratory drilling program in one of the hottest plays in the United States. We increased our midstream capacity in Butler County through new, long-term contracts and the commissioning of a second cryogenic processing facility, and we expanded our production to greater realize this capacity. Most importantly, we continued to operate in a safe and environmentally responsible manner in each of our project areas. This intense focus on execution yielded significant financial and operational results for our company. We increased our average daily production by 72% and grew our proved reserves by 69% over 2011. We decreased our cash operating costs, realizing a 17% decrease in lease operating expense per Mcfe and a 47% decrease in cash G&A expense per Mcfe over 2011. We strengthened our balance sheet, strategically divesting our midstream assets and opportunistically accessing the debt markets. Finally, we continued to protect our revenues from volatile commodity markets through our disciplined hedging program, which added more than $16 million in cash to our 2012 operating cash flows. These are remarkable achievements and we're proud to have delivered on our commitments for 2012.

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OUR STORY

LANDOWNERS

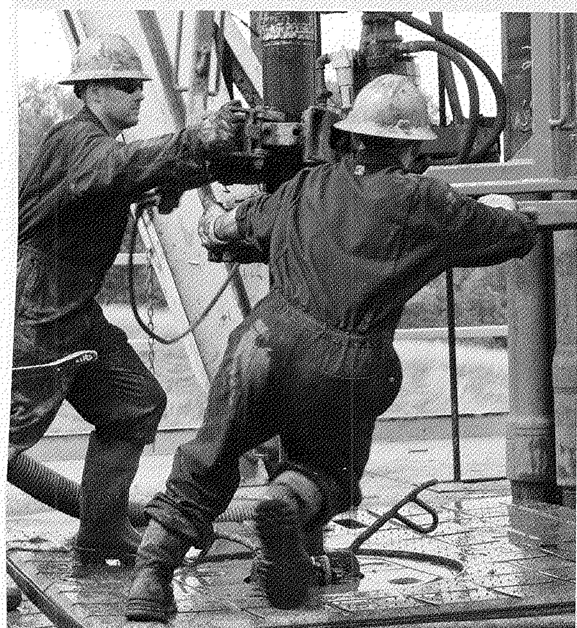
ACREAGE

DRILLING

FOCUS • PERFORM • ACHIEVE

Thomas Stabley
Chief Executive Officer

"Our strong asset base and commitment to execution are competitive advantages that will enable us to drive growth and create long term value for our shareholders."



2012 HIGHLIGHTS

We entered the year with strong momentum from our 2011 initiatives, enabling us to strategically focus on building our liquids production profile. In our Butler Operated Area, we successfully established the viability of three producing horizons – the Marcellus, the Upper Devonian Burkett and the Utica. Based on our Marcellus well results, we established a "Super Rich" area in the northwest portion of the field that provides superior economics due to the high liquids content of the production. Throughout the year, we continued to refine our "Super Frac" completion technique, which significantly contributed to the increase in EURs of our wells. We also placed into service our first Upper Devonian Burkett Shale well, and through it established not only the productivity of the formation, but also the significant liquids content of the Burkett Shale. This was an exciting development for us, as the viability and productivity of the Upper Devonian Burkett enables us to selectively exploit two liquids-rich formations, dramatically increasing the number of future drilling locations and the resource potential of our Butler Operated Area.

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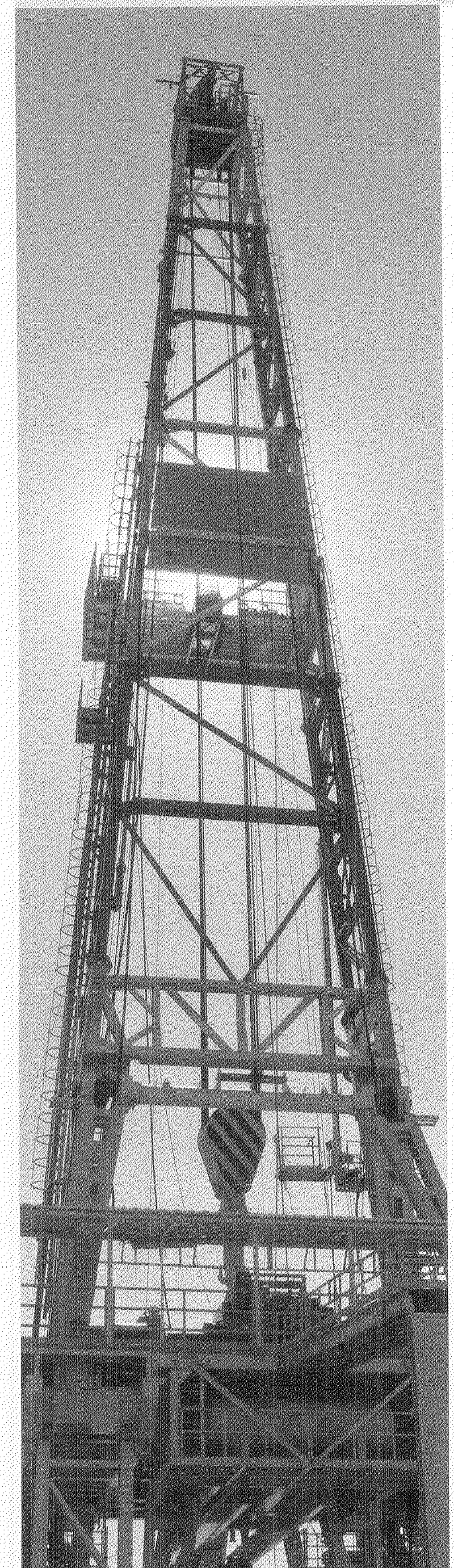
PRODUCTION INVENTORY RECLAMATION

OPERATIONAL EXCELLENCE



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Equally exciting for us was the growth of our position in the Ohio Utica Shale. As we entered 2012, we held approximately 15,000 net acres in Carroll County, Ohio, which we call the Warrior North Prospect. As 2012 evolved, we continued to add acreage to our established position and have since grown our holdings in the Ohio Utica Shale to approximately 20,000 net acres, including the formation of a new core acreage position, the Warrior South Prospect, located in Noble, Guernsey and Belmont Counties, Ohio. The Ohio Utica Shale has garnered a lot of attention over the past year due to the increased amount of activity in the region and the successful initial well results of both Rex Energy and our peers. In the Warrior North Prospect, we drilled, completed and placed into service our first well and our results compared quite favorably to our industry peers. In the Warrior South Prospect, we drilled and completed our first three wells and will place them into service in 2013. We are extremely excited for what the future holds in the Ohio Utica Shale and continue to refine and enhance our drilling and completion techniques in the region. In the Appalachian Basin (including both our Pennsylvania and Ohio positions), we now hold over 100,000 net acres, a significant milestone in the company's history.

In the Illinois Basin, we continued to develop our ASP project during 2012, successfully booking proved reserves on our first commercial scale development project, the Delta Unit. In addition, in mid 2012, we initiated a conventional drilling and re-completion program with the goal of increasing our oil production. During the remainder of the year, we successfully drilled and completed 8 wells and re-completed 15 additional wells in the Illinois Basin. The 23 wells that we completed in 2012 more than doubled our initial production goals for the program. These early successes have encouraged us to expand the program and to explore further opportunities in the Illinois Basin. In 2013, we expect to drill and re-complete an additional 28 wells and we also plan to drill a horizontal test well in the region.

These and other operational successes in 2012 enabled us to increase our production rate to 67.1 MMcfe per day - an increase of 72% over the average daily production rate in 2011. In addition, our focus on liquids production growth helped us exit 2012 with a liquids production mix of approximately 30%. Through the consistent execution of our business plan, we achieved our 10th consecutive quarter of production growth in the fourth quarter of 2012.

Finally, 2012 saw us embark on and complete a number of significant financial initiatives that will provide Rex Energy with the strength and flexibility to execute our strategic plans for the future. In May 2012, we sold our midstream interests in the Butler Operated Area, including the two cryogenic gas processing plants, for $512 million or approximately $120 million in net proceeds to Rex. In December 2012, we completed an offering of $250 million of senior notes and retired our second lien term loan. We entered 2013 with over $280 million in liquidity and a hedging portfolio that will help to ensure we have the capital needed to fund our targeted growth plans and the strategic development of our assets.

FOCUSED ON GROWTH

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OUR PRIORITIES FOR 2013

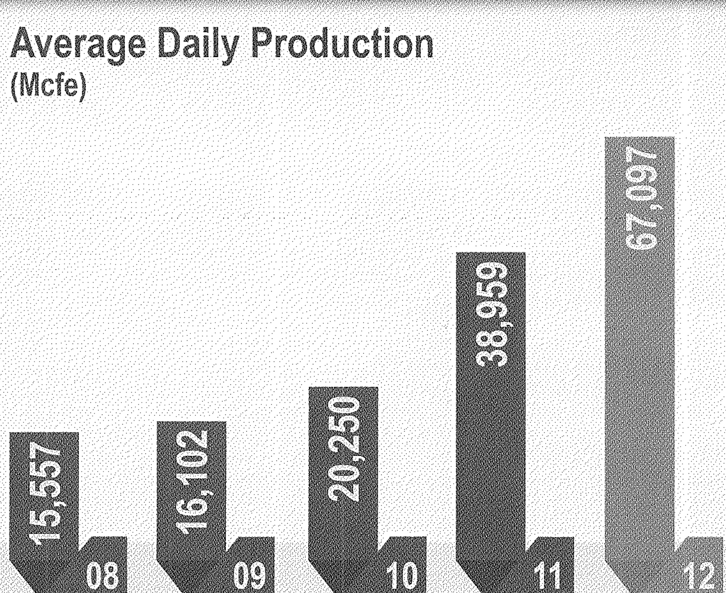
- Operate in a safe and environmentally responsible manner
- Target production growth from our liquids rich regions
- Execute our 2013 drilling and strategic plans
- Control drilling and operating costs
- Acquire accretive acreage in our core operating regions
- Expand our conventional drilling and re-completion program in the Illinois Basin
- Maintain a strong balance sheet

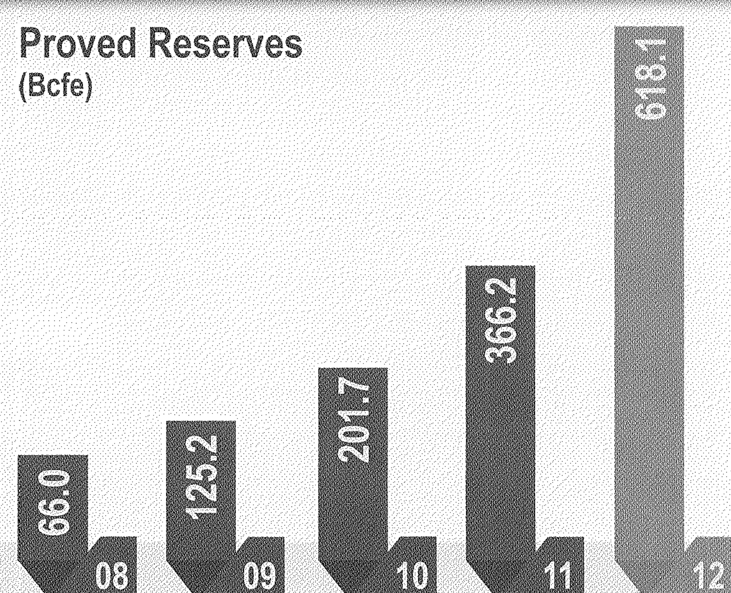
LOOKING FORWARD

2012 was an extremely successful year for Rex Energy. That said, as I think about 2013 and beyond, I cannot help but look forward to what lies ahead of us with great enthusiasm. We have exciting plans for 2013 and we are more confident than ever that the continued execution of our strategy will drive further growth and enable us to deliver on our commitments. We have built a tremendous team of talented employees at Rex Energy, and I believe we have never been in a better position to deliver value to our shareholders. On behalf of the Board of Directors and the entire Rex Energy team, I thank you for your continued support of our company.

Sincerely,

Thomas C. Stabley
Chief Executive Officer





OPERATING AREAS

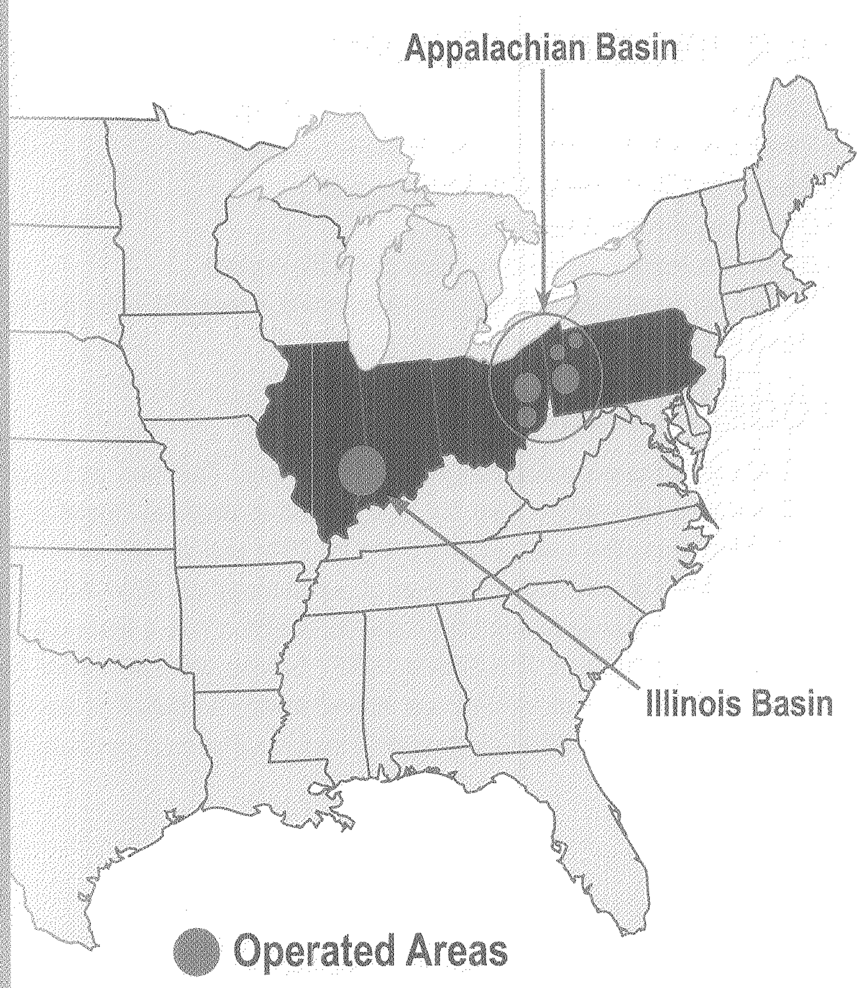
Rex Energy operates in two main areas within the United States: the Appalachian Basin and the Illinois Basin. In the Appalachian Basin, we are focused on natural gas and natural gas liquids production. In the Illinois Basin, our operations are focused on conventional oil production and enhanced oil recovery projects.

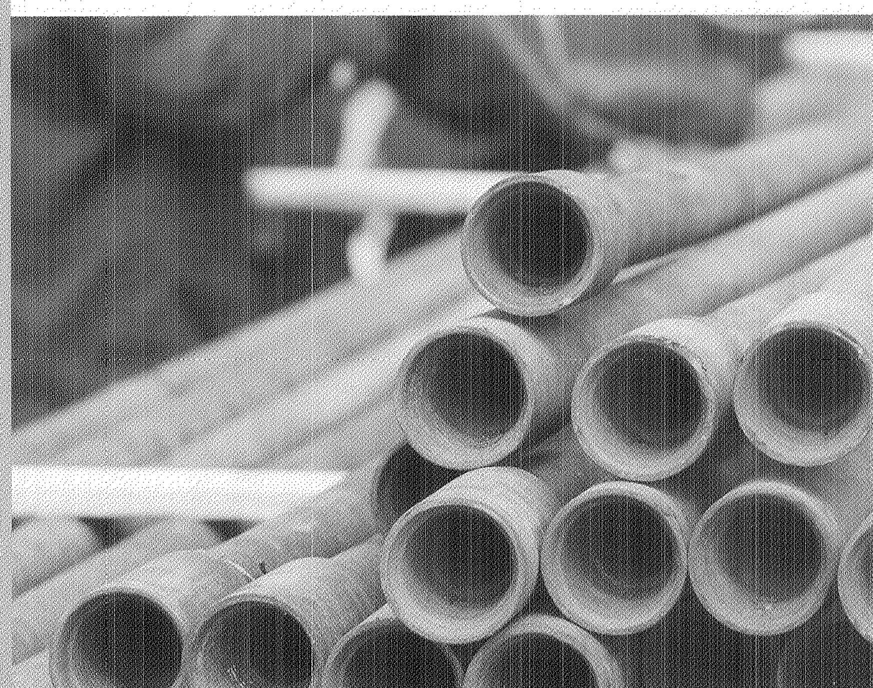
Appalachian Basin

Our operations are principally focused on the Marcellus, Upper Devonian Burkett and Utica Shale's in the Appalachian Basin. In Pennsylvania, Rex Energy operates and has a 70% working interest in the Butler Operated Area which is prospective for multiple producing horizons, including the Marcellus Shale, Upper Devonian Burkett Shale and the Utica Shale. Rex Energy currently operates 55 wells in the Butler Operated Area. In 2012, we began operating in our Ohio Utica areas, which we refer to as our "Warrior North Prospect" located in Carroll County, Ohio and our "Warrior South Prospect" located in Guernsey, Noble and Belmont Counties, Ohio. We hold approximately 20,000 net acres in our Ohio Utica areas, which we believe is located within the liquids-rich window of the Utica Shale. As of December 31, 2012, we have drilled and completed 4 wells in our Ohio Utica Area and placed one into sales.

Illinois Basin

Rex Energy is one of the largest oil producers in the Illinois Basin, which is one of the largest, mature oil-producing basins in the U.S. It is estimated to have produced over four billion barrels of oil since production commenced in the early 1900's. As of December 31, 2012, we operated approximately 28,900 gross (27,000 net) acres and had interests in approximately 1,000 producing oil wells. Our conventional and EOR investments have increased average daily production from 1,900 Boe/d in 2011 to 1,965 Boe/d in 2012.





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, 2012

Commission file number: 001-33610

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

Delaware	**20-8814402**
(State or other Jurisdiction of Incorporation or Organization)	**(I.R.S. employer identification number)**

476 Rolling Ridge Drive, Suite 300
State College, Pennsylvania 16801
(Address of Principal Executive Offices)
(Zip Code)

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

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

Title of each class	Name of each exchange on which registered
Common Stock, $.001 par value per share	**The NASDAQ Global Select Market**

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

None

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

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

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

Indicate by check mark 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 (§232.405 of this chapter) 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 (§229.405) 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 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 ☐ Smaller reporting company ☐

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of June 29, 2012 was $405,781,897. This amount is based on the closing price of the registrant's common stock on the NASDAQ Global Market on that date. Shares of common stock beneficially held by executive officers and directors of the registrant are not included in the computation. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

53,228,771 common shares, $.001 par value, were outstanding on March 7, 2013.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement for its 2013 Annual Meeting of Stockholders to be held on May 8, 2013, are incorporated by reference herein in Items 10, 11, 12, 13 and 14 of Part III of this report.

REX ENERGY CORPORATION

FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2012

Unless otherwise indicated, all references to "Rex Energy Corporation," "the Company," "our," "we," "us" and similar terms refer to Rex Energy Corporations and its subsidiaries. Natural gas is converted throughout this report at a rate of six Mcf of gas to one barrel of oil equivalent ("Boe"). NGLs are converted throughout this report at a rate of one barrel of NGLs to one Boe. The ratios of six Mcf of gas to one Boe and one barrel of NGLs to one Boe do not assume price equivalency and, given price differentials, the price for a Boe of natural gas or NGLs may differ significantly from the price of a barrel of oil.

If you are not familiar with the oil and gas terms or abbreviations used in this report, please refer to the definitions of these terms and abbreviations under the caption "Glossary" at the end of "Item 15. Exhibits and Financial Statement Schedules" of this report.

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CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING STATEMENTS

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

These forward-looking statements are subject to numerous assumptions, risks, and uncertainties. Factors 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:

- economic conditions in the United States and globally;
- conditions in the domestic and global capital and credit markets and their effect on us;
- domestic and global supply and demand for oil, NGLs and natural gas;
- volatility in oil, NGL and natural gas pricing;
- new or changing government regulations, including those relating to environmental matters, permitting or other aspects of our operations;
- the geologic quality of our properties with regard to, among other things, the existence of hydrocarbons in economic quantities;
- uncertainties inherent in the estimates of our oil, NGL and natural gas reserves;
- our ability to increase oil, NGL and natural gas production and income through exploration and development;
- drilling and operating risks;
- the success of our drilling techniques in both conventional and unconventional reservoirs;
- the success of the secondary and tertiary recovery methods we utilize or plan to employ in the future;
- the number of potential well locations to be drilled, the cost to drill, and the time frame within which they will be drilled;
- the ability of contractors to timely and adequately perform their drilling, construction, well stimulation, completion and production services;
- the availability of equipment, such as drilling rigs, and infrastructure, such as transportation, pipelines, processing and midstream services;
- the effects of adverse weather or other natural disasters on our operations;
- competition in the oil and gas industry in general, and specifically in our areas of operations;
- changes in our drilling plans and related budgets;
- the success of prospect development and property acquisitions;
- the success of our business and financial strategies, and hedging strategies;
- the adequacy and availability of our capital resources, credit and liquidity including, but not limited to, access to additional borrowing capacity;
- uncertainties related to the legal and regulatory environment for our industry and our own legal proceedings and their outcome; and
- other factors discussed under "Item 1. Risk Factors" of this report.

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, which speak only as of the date of this report. Other unknown or unpredictable factors may cause actual results to differ materially from those projected by the forward-looking statements. Most of these factors are difficult to anticipate and may be beyond our control. 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.

All forward-looking statements attributable to us are expressly qualified in their entirety by these cautionary statements.

PART I

ITEM 1. BUSINESS

General

We are an independent oil and gas company operating in the Appalachian Basin and Illinois Basin. In the Appalachian Basin, we are focused on our Marcellus Shale, Utica Shale and Upper Devonian Shale drilling and exploration activities. In the Illinois Basin, we are focused on the implementation of enhanced oil recovery on our properties as well as conventional oil production. We pursue a balanced growth strategy of exploiting our sizable inventory of high potential exploration drilling prospects while actively seeking to acquire complementary oil and natural gas properties. In addition to our drilling and exploration activities, we are also engaged in oil and gas field services, where we provide water sourcing, water disposal and water transfer capabilities for completion operations.

We are headquartered in State College, Pennsylvania, and have regional offices in Bridgeport, Illinois; Butler, Pennsylvania; Seven Fields, Pennsylvania; and Carrolton, Ohio.

We were incorporated in the state of Delaware on March 8, 2007. Our common stock currently trades on the NASDAQ Global Select Market under the symbol "REXX". The information set forth in this report is exclusive of our discontinued operations related to the Southwest Region and DJ Basin properties, unless otherwise noted, which are classified as Discontinued Operations on our Consolidated Statements of Operations and Assets Held for Sale on our Consolidated Balance Sheets.

At December 31, 2012, our estimated proved reserves had the following characteristics:

- 618.1 Bcfe;
- 60.1% natural gas and 39.9% crude oil and natural gas liquids ("NGLs");
- 41.7% proved developed; and
- a reserve life index of approximately 25.2 years (based upon 2012 production).

At December 31, 2012, we operated approximately 2,173 wells, which include approximately 534 disposal and injection wells. For the quarter ended December 31, 2012, we produced an average of 73.9 net MMcfe per day, composed of approximately 70.9% natural gas and 29.1% oil and NGLs.

We are one of the largest oil producers in the Illinois Basin, with average net production of 1,965 barrels of oil per day in 2012. In addition to our developmental shallow oil drilling in the Illinois Basin, we have implemented an enhanced oil recovery project, or EOR project, in the Lawrence Field in Lawrence County, Illinois, which we refer to as our Lawrence Field alkali-surfactant-polymer, or ASP, Flood Project. During 2010, we commenced chemical injection into our Middagh ASP pilot unit. During 2011, we received initial and peak production response from the project and production levels have begun a gradual decline. In 2012, we initiated ASP injection on the Perkins-Smith unit for which initial production response is expected during the second or third quarter of 2013 with peak production response expected during the fourth quarter of 2013. All drilling and infrastructure construction has been completed for the next planned unit, the Delta Unit. ASP injection in the Delta Unit is expected to commence during the fourth quarter of 2013. The success to date of our ASP development resulted in the assignment of approximately 874.0 MBls of estimated proved reserves as of December 31, 2012.

In the Appalachian Basin during 2012, we averaged net production of approximately 55.3 MMcfe per day of natural gas, NGLs and condensate. In 2012, we grew our reserves and production in the region primarily through Marcellus Shale and Utica Shale drilling projects. As of December 31, 2012, we controlled approximately 128,000 gross (70,500 net) acres, which includes both developed and undeveloped acreage, in areas of Pennsylvania that we believe are prospective for Marcellus Shale exploration and approximately 112,700 gross (80,200 net) acres, which includes both developed and undeveloped acreage, in Pennsylvania and Ohio that we believe are prospective for Utica Shale exploration. In addition as of December 31, 2012, we controlled approximately 69,400 gross (48,400 net) acres in Pennsylvania that we believe are prospective for Upper Devonian (Burkett) liquids-rich exploration.

Our total operating revenue for the year ended December 31, 2012 was $148.1 million. Revenue was derived from $134.6 million in oil, natural gas and NGL sales, $13.4 million in field services revenue and $0.2 million in other revenue.

For the year ended December 31, 2012, we drilled 42.0 gross (30.2 net) wells, which excludes wells that have been drilled in anticipation of future ASP development. We placed into sales 38.0 gross (25.8 net) wells during 2012, and ended the year with 31.0 gross (19.7 net) wells in inventory that are awaiting completion.

The following table sets forth selected data concerning our continuing operations for production, estimated proved reserves and undeveloped acreage in our two operating regions for the periods indicated:

Basin/Region	2012 Average Daily Mcfe[1]	Total Proved Bcfe (as of December 31, 2012)	Percent of Total Proved Bcfe	PV-10 (as of December 31, 2012) (in millions)[2]	Total Net Undeveloped Acres (as of December 31, 2012)[3]
Illinois Basin	11,790	54.9	8.9%	$222.2	1,700
Appalachian Basin	55,307	563.2	91.1%	278.3	70,700
Total	67,097	618.1	100.0%	$500.5	72,400

1 Oil and NGLs are converted at the rate of one BOE to six Mcfe.

2 Represents the present value, discounted at 10% per annum (PV-10), of our estimated future net cash flows of our estimated proved reserves before income tax and asset retirement obligations. PV-10 is a non-GAAP financial measure because it excludes the effects of income taxes and asset retirement obligations. The most directly comparable GAAP measure is standardized measure of discounted future net cash flows. The standardized measure of discounted future net cash flows includes the effects of estimated future income tax expenses and asset retirement obligations and is calculated in accordance with Accounting Standards Topic 932. Standardized measure is based on proved reserves as of fiscal year-end calculated using the unweighted arithmetic average first-day-of-month prices for the prior 12 months. PV-10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as defined under GAAP. At December 31, 2012, our standardized measure was $396.1 million. For an explanation of why we show PV-10 and a reconciliation of PV-10 to the standardized measure of discounted future net cash flows, please read "Selected Financial and Operating Data—Non-GAAP Financial Measures." Please also read "Risk Factors—Our estimated proved 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."

3 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 estimated proved reserves.

Our Competitive Strengths

We believe our strengths provide us with significant competitive advantages and position us to successfully execute our business and growth strategies.

High Quality Asset Base. In the Appalachian Basin, we are focused on developing our acreage that we believe to be prospective for three liquids-rich producing zones, including the Marcellus Shale, the Upper Devonian Shales and the Utica Shale. As of December 31, 2012, we had completed at least one well in each of these zones. Approximately $200.0 million of our 2013 operating capital budget is allocated to the continued development of these three producing zones. In the Illinois Basin, which is 100% oil producing, we are focused on conventional drilling and recompletion projects. Additionally, due to the success of our pilot ASP programs in the Lawrence Field, we are implementing our first commercial scale ASP flood, our Delta Unit. We have allocated approximately $48.0 million of our 2013 operating capital budget to conventional and EOR opportunities in the Illinois Basin. A substantial portion of our acreage holdings are in liquids-rich areas prospective for oil, condensate and NGL production. As of December 31, 2012, our holdings prospective for liquids-rich production accounted for approximately 82.9% of our total net acreage.

Track Record of Reserve and Production Growth. Our management and operations teams have a proven track record of performance and have consistently demonstrated our ability to acquire and develop reserves at attractive costs in the basins in which we operate. As a result of this operational success, between December 31, 2009 and December 31, 2012, our proved reserves have grown at a compound annual growth rate ("CAGR") of 70.3%. During the same time period, our proved natural gas and NGL reserves grew at a CAGR of 106.8%. We believe we have competitive finding and development costs as compared to our industry peers. Our annual production has grown at a CAGR of 61.1% between December 31, 2009 and December 31, 2012. Additionally, as of December 31, 2012, we had an inventory of 25.0 gross (16.2 net) wells drilled and awaiting completion in our core operations area in the Appalachian Basin, with four gross (2.7) net wells completed and awaiting pipeline infrastructure. Our 2013 drilling program provides for the drilling of an additional 30.0 gross wells in locations we believe to be similarly prospective for liquids-rich production. To date, we have achieved a 100% success rate on our drilling program in this area of our operations. We believe that our strong operating history and strategic location of potential drilling sites will continue to provide us with further low-risk development opportunities in this area.

Significant Operational Control in Our Core Areas. As a result of successfully executing our strategy of acquiring concentrated acreage positions and operating properties with a high working interest, we operate and manage approximately 84.8% of our net acreage. Our high percentage of operated properties enables us to exercise a significant level of control with respect to drilling, production, operating and administrative costs, in addition to leveraging our base of technical expertise in our core operating areas.

Financial Flexibility to Fund Growth. As of December 31, 2012, we had liquidity of $284.0 million consisting of $240.0 million available under our senior credit facility and cash on hand of approximately $44.0 million, which we believe combined with cash flow from our operations will be sufficient to fund our operations through 2013 and into 2014. We seek to maintain financial flexibility to allow us to actively develop our assets and execute attractive acquisition opportunities.

Business Strategy

Our strategy is to create value by profitably increasing our reserves, production, cash flow and earnings. Key elements of our strategy include:

Develop Our Existing Properties. Our core leasehold consists entirely of interests in developed and undeveloped crude oil, NGL and natural gas resources located in the Appalachian and Illinois basins. We intend to pursue an active, technology-driven drilling program to develop and maximize the value of our existing acreage. We actively allocate capital between our two core basins in an effort to maximize value and estimated proved reserve growth based on our assessment of the relative risk of development and the economics of potential projects. Additionally, by concentrating our drilling and producing activities in our core areas, we are able to develop the regional expertise needed to interpret specific geological and operating trends and develop economies of scale in our operations. Our areas of focus include:

- our Marcellus Shale play with approximately 128,000 gross (70,500 net) acres;
- our Utica Shale play with approximately 112,700 gross (80,200 net) acres;
- our Burkett Shale play (an Upper Devonian Shale) with approximately 69,400 gross (48,400 net) acres;
- our Lawrence Field ASP Flood Project in Illinois; and
- our conventional drilling and recompletion projects in the Illinois Basin.

Employ Technological Expertise. We intend to utilize and expand the technological expertise that has enabled us to achieve a drilling success rate of approximately 96.8% (approximately 98.7% excluding assets currently held for sale) over the last three years, to improve operations and to enhance field recoveries. We intend to continue to apply this expertise to our proved reserve base and our development projects.

Reduce Per Unit Operating Costs Through Economies of Scale and Efficient Operations. As we continue to increase our production and develop our existing properties, we believe that our per unit production costs can benefit from leveraging our existing infrastructure and expertise over a larger number of wells. Our acreage positions are tightly concentrated, which we believe will enable us to achieve greater cost efficiencies in our drilling and completion operations than those of our competitors who have less consolidated positions. As we continue to develop our acreage positions, we expect to realize increased capital efficiencies through greater utilization of multi-well pads and existing infrastructure and facilities.

Maintain Financial Flexibility. Because of the volatility of commodity prices and the risks involved in our industry, we believe in maintaining a conservative balance sheet and remaining flexible in our capital budgeting process. Our high percentage of operated properties enables us to exercise a significant level of control with respect to drilling, production, operating and administrative costs. We may pursue joint ventures, asset sales or defer capital projects in order to ensure that we are able to quickly adapt to changing industry conditions.

Manage Commodity Price Exposure Through an Active Hedging Program. We actively hedge our future exposure to commodity price fluctuations by entering into oil, natural gas and NGL swaps and collars. This strategy is designed to provide us with stability in our cash flows to support our on-going capital requirements. As of December 31, 2012, we had approximately 98.2%, 90.4% and 30.2 % of our 2012 volumes for oil, natural gas and NGLs hedged for calendar year 2013, respectively. Additionally, we had approximately 49.2% and 59.9% of our 2012 volumes for oil and natural gas hedged for calendar year 2014, respectively.

Significant Accomplishments in 2012

During 2012, our significant accomplishments were as follows:

- **Completed public offering of common stock and private placement of senior notes.** During 2012, we completed a public offering of common stock as well as a private offering of senior notes raising a combined $312.8 million after discounts and expenses. As of December 31, 2012, we had approximately $44.0 million in cash on hand with no amounts drawn on our available senior credit facility of $240.0 million.
- **Completed sale of Butler County, Pennsylvania midstream assets.** On May 29, 2012, we closed the sale of our ownership in Keystone Midstream Services, LLC ("Keystone Midstream"). The base consideration for the sale was $483.2 million after adjustments for closing cash, working capital and outstanding debt. Our net proceeds, based on our 28% ownership of Keystone Midstream, totaled $128.1 million, net of post-closing adjustments. Approximately $7.2 million remains in an escrow account that will be distributed in June 2013, pending the need to use any of the remaining escrowed amount for qualified repairs of the midstream assets or other purposes permitted under the applicable agreements.
- **Drilled, completed and placed into service our first Ohio Utica Shale well.** During 2012, we drilled, completed and placed into service our first Ohio Utica Shale well, the Brace 1H, which had an initial 24-hour sales rate, assuming full ethane recovery, of 6.6 MMcfe per day comprising approximately 70% liquids (43% NGLs and 27% condensate). In addition to the Brace 1H, we have drilled three wells in the southern portion of our Ohio Utica Shale acreage which are awaiting infrastructure and pipeline connections. Our 2013 plans call for the drilling of nine gross (8.1 net) wells in the Ohio Utica Shale.
- **Continued expansion of marketing, transportation and processing arrangements for Appalachian production.** As of December 31, 2012, we had long-term marketing agreements in place for approximately 78.5 MMcf per day of natural gas, of which approximately 64.5 MMcf is currently in

effect with the remaining volumes expected to be in effect by the fourth quarter of 2013. In addition to our marketing agreements for natural gas, during 2012 we entered into various transportation and processing arrangements for our Ohio Utica Shale production, supplementing pre-existing arrangements for our operated Appalachian production. We now have several processing agreements in place to separate our NGLs from our produced natural gas. In total, these agreements currently call for 65.0 MMcf of gross inlet natural gas volumes and increase to 205.0 MMcf of gross inlet volumes in 2015. We also entered into a transportation agreement for produced ethane, expected to become effective in 2014, which initially calls for a commitment of 3,000 gross barrels per day.

- **Horizontal drilling success.** In our operated areas of the Appalachian Basin we drilled 26.0 gross (19.0 net) wells and placed 23.0 gross (15.3 net) wells into service during 2012. As of December 31, 2012, we had 29.0 gross (18.8 net) wells awaiting completion or pipeline infrastructure between our operated and non-operated areas in the Appalachian Basin.

- **ASP reserves.** Due to the success of our ASP pilot projects we successfully assigned estimated proved non-producing reserves of 758.3 MBls for our Delta Unit. We currently are awaiting the initial response from our Perkins-Smith Unit, which has estimated proved non-producing reserves of 77.0 MBls. Initial response is expected during the second or third quarter of 2013, and we have completed drilling and infrastructure construction for our first full commercial unit, the Delta Unit.

- **Decrease in lease operating expenses.** We have decreased our lease operating expenses, on a per-unit of production basis, for four consecutive years, from $4.66 per Mcfe in 2008 to $1.94 per Mcfe in 2012.

- **Production growth.** Due to the success of our development programs in the Appalachian and Illinois basins, we increased our total production by 72.7% over 2011. Specifically, our oil production increased 5.4%, NGL production increased 88.3% and natural gas production increased 102.2%.

- **Reserves growth.** Our total estimated proved reserves increased approximately 68.8% over 2011, consisting of an increase of 14.6% in estimated proved oil reserves, an increase of 344.0% in estimated proved NGL reserves and an increase of 35.5% in estimated proved natural gas reserves.

- **Continued expansion of drilling inventory.** To continue to grow, the size of our prospect inventory must remain large. As of December 31, 2012, we controlled approximately 128,000 gross (70,500 net) acres prospective for the Marcellus Shale, 112,700 gross (80,200 net) acres prospective for the Utica Shale and 69,400 gross (48,400 net) acres prospective for the Burkett Shale. In addition, as of December 31, 2012, we had proved undeveloped ("PUD") reserves of approximately 360.1 Bcfe, comprising 100.0 gross PUD well locations.

Plans for 2013

Our budgeted capital spending for 2013 is approximately $250.0 million. The capital budget contemplates the drilling of approximately 19.0 gross (13.3 net) horizontal Marcellus, Utica and Upper Devonian Shale wells in Butler County, Pennsylvania. We have plans to complete 22.0 gross (15.4 net) wells within Butler County, Pennsylvania. In our Ohio operating area, we plan to drill 11.0 gross (10.1 net) horizontal Utica Shale wells and complete nine gross (8.1 net) horizontal Utica Shale wells. Within our joint venture areas with WPX Energy, for which WPX Energy serves as the operator, we do not plan to drill any wells in 2013; however, we do expect to complete seven gross (2.8 net) wells within those areas that were previously drilled.

Within the Illinois Basin, our budget of approximately $24.0 million contemplates the drilling and completion of 17.0 gross (17.0 net) wells, in addition to the recompletion of nine gross (nine net) wells that were previously drilled as a part of our legacy conventional program. The remaining budget in the Illinois Basin includes $12.0 million for further development of the Lawrence Field ASP project and $12.0 million for facility and infrastructure upgrades.

The following table summarizes our actual 2012 and our budgeted 2013 capital expenditures. The estimated capital expenditures are dependent on a number of factors, including industry conditions and our drilling success, and are subject to change. We do not attempt to budget for future acquisitions of proved oil and gas properties.

	For the Years Ended December 31, ($ in thousands)	
	2012 (Actual)	2013 (Estimated)
Capital Expenditures		
Illinois Basin Drilling & Facility	$ 20,902	$ 36,000
Illinois Basin Enhanced Oil Recovery	12,845	12,000
Illinois Basin Other	1,070	—
Appalachian Basin Drilling & Facility	141,774	200,000
Appalachian Basin Midstream[1]	4,087	2,000
Appalachian Basin Other	2,980	—
Other Corporate Expenditures	4,167	—
Total Capital Expenditures[2,3]	$187,825	$250,000

1 Includes contributions to equity method investments and consolidated subsidiaries.

2 Capital expenditures for the acquisition of unproved properties for the year ended December 31, 2012 totaled approximately $51.8 million.

3 Actual expenditures for 2012 and estimated expenditures for 2013 do not contemplate any amounts for our assets in the DJ Basin, which are recorded as Assets Held for Sale on our Consolidated Balance Sheets.

Production, Revenues and Price History

The following table sets forth information regarding oil and gas production and revenues from continuing operations for the last three years:

	Production and Revenue by Region For the Years Ended December 31, ($ in thousands)		
	2012	2011	2010
Appalachian Region:			
Revenue	$ 69,260	$ 48,444	$ 14,652
Oil Production (Bbls)	12,875	1,043	108
Natural Gas Production (Mcf)	18,016,700	8,912,250	3,088,598
NGL Production (Bbls)	358,049	190,151	25,559
Total Production (Mcfe)[1]	20,242,244	10,059,414	3,242,600
Oil Average Sales Price	$ 78.83	$ 76.91	$ 41.63
Natural Gas Average Sales Price	$ 2.94	$ 4.28	$ 4.46
NGL Average Sales Price	$ 42.60	$ 53.66	$ 33.60
Average Production Cost per Mcfe[2]	$ 1.23	$ 1.10	$ 1.13

	Production and Revenue by Region For the Years Ended December 31, ($ in thousands)		
	2012	2011	2010
Illinois Region:			
Revenue	$ 65,314	$ 63,435	$ 52,572
Oil Production (Bbls)	719,191	693,409	691,466
Natural Gas Production (Mcf)	—	—	—
NGL Production (Bbls)	—	—	—
Total Production (Bbls)	719,191	693,409	691,466
Oil Average Sales Price	$ 90.82	$ 91.48	$ 76.03
Natural Gas Average Sales Price	$ —	$ —	$ —
NGL Average Sales Price	$ —	$ —	$ —
Average Production Cost per Bbl[2]	$ 30.71	$ 29.36	$ 29.68
Total Company[2]			
Revenue	$ 134,574	$ 111,879	$ 67,224
Oil Production (Bbls)	732,066	694,452	691,574
Natural Gas Production (Mcf)	18,016,700	8,912,250	3,088,598
NGL Production (Bbls)	358,049	190,151	25,559
Total Production (Mcfe)[1]	24,557,390	14,219,868	7,391,396
Oil Average Sales Price	$ 90.61	$ 91.46	$ 76.03
Natural Gas Average Sales Price	$ 2.94	$ 4.28	$ 4.46
NGL Average Sales Price	$ 42.60	$ 53.66	$ 33.60
Average Production Cost per Mcfe[2]	$ 1.91	$ 2.30	$ 3.25

1 Oil and NGLs are converted at the rate of one BOE to six Mcfe.

2 Excludes ad valorem and severance taxes.

Competition

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

Employees

As of December 31, 2012, we had 230 full-time employees, 122 of whom were field personnel. No employees are represented by a labor union or covered by any collective bargaining arrangement. We believe that our relations with our employees are good. We regularly utilize independent consultants and contractors to perform various professional services, particularly in the areas of drilling, completion, field services, oil and gas leasing and on-site production operation services.

Marketing and Customers

We market nearly all of our oil production from the properties that we operate in the Illinois Basin for both our interest and that of the other working interest owners and royalty owners. The majority of our oil is stored at well site tanks and sold to CountryMark Cooperative, LLP ("CountryMark"), a local refinery, currently at a premium to the basin-posted prices. We receive this premium due to our significant size in the basin relative to other local producers. Purchasers, including CountryMark, purchase our oil at our tank facilities and truck the oil to their refinery facilities. The revenue that we derived from our sales to CountryMark constituted approximately 48.1% of our oil, NGL and natural gas revenue from continuing operations in 2012. As such, we are currently significantly dependent on the creditworthiness of CountryMark. We have taken steps to monitor the creditworthiness of CountryMark, including obtaining a letter of credit corresponding to a significant portion of its projected monthly revenue. For additional information, see "Risk Factors—*We depend on a relatively small number of purchasers for a substantial portion of our revenue. The inability of one or more of our purchasers to meet their obligations or the loss of our market with CountryMark Cooperative, LLP, in particular, may adversely affect our financial results,"* in "Item 1A. Risk Factors" in this report.

In December 2009, we entered into a Master Crude Purchase Agreement (the "Master Crude Purchase Agreement") with CountryMark that became effective as of January 1, 2010. Under the terms of the agreement, we agreed to sell, supply and deliver to CountryMark, and CountryMark agreed to receive and purchase from us, crude oil pursuant to purchase and sale order confirmations that we and CountryMark may enter into from time to time. Under the agreement, until we enter into a confirmation with CountryMark, neither party is under an obligation to purchase or sell any crude oil. The Master Crude Purchase Agreement provides that the term will automatically be extended for additional one-year periods unless, prior to October 1 of each year, either party gives written notice to the other. We have historically entered into confirmations for approximately one-year periods, although the terms of the confirmations have varied. For 2012, we entered into a confirmation with CountryMark, under which CountryMark purchased substantially all of the crude oil that we produced in 2012 in the Illinois Basin. That confirmation extends to purchases through September 2013. The confirmation does not obligate us to provide a specific volume of crude oil, and as of December 31, 2012, we were not committed to any delivery levels with CountryMark or any other party. In addition to the arrangements with CountryMark, we also have an offload facility at a nearby crude oil pipeline that Marathon Oil Corp. ("Marathon") operates that has enabled us to diversify our purchasers in the Illinois Basin.

In the Appalachian Basin, our natural gas producing properties are located near existing pipeline systems and processing infrastructure. For properties that we operate in the Appalachian Basin, our natural gas production, and that of our working interest partners, is currently marketed by BP Energy Company ("BP Energy"). In Butler County, Pennsylvania, we are obligated to provide to BP Energy, and BP Energy is obligated to purchase from us, a minimum monthly volume of natural gas equivalent to 64,500 MMBtu per day. In Ohio, we have a marketing agreement in place with BP Energy for 14,000 MMBtu per day which is expected to commence during the fourth quarter of 2013. We also have a transportation agreement with Dominion East Ohio allowing for the gathering and transport of approximately 15,000 MMBtu per day of natural gas. We have a number of additional processing and marketing arrangements in place for our Ohio production, but those arrangements do not commit us to definite volumes.

Prices for oil and natural gas fluctuate widely based on, among other things, supply and demand. Supply and demand are influenced by a number of factors, including weather, foreign policy, industry practices and the U.S. and worldwide economic climate. Oil and natural gas markets have historically been cyclical and volatile in nature as a result of many factors that are beyond our control. There can be no assurance of what price we will be able to sell our oil and natural gas. Prices may be low when our wells are most productive, thereby reducing overall returns.

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

Governmental Regulations

Our oil and natural gas exploration, production, and related operations are subject to extensive statutory and regulatory oversight by federal, state, tribal and local authorities. We must, for example, obtain drilling permits, post bonds for drilling, operating, and reclamation, and submit various reports. The following activities are also subject to regulation: the location of wells, the method of drilling completion and operating wells, secondary and enhanced oil recovery projects, notice to surface owners and third parties, the surface development, use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, temporary storage tank operations, air emissions from flaring, compression and access roads, the impoundment of water, the manner and extent of earth disturbances, air emissions, sour gas management, the disposal of fluids used in connection with operations, and the calculation and distribution of royalty payments and production taxes. We must also comply with statutes and regulations addressing conservation matters, including the size of drilling and spacing units, or proration units, the number of wells that may be drilled in an area, the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production. Failure to comply with any of these requirements can result in substantial monetary penalties or lease cancellation. Finally, in the past tribal and local authorities have imposed moratoria or other restrictions on exploration and production activities that must be addressed before those activities can proceed. Moreover most states impose a production, ad valorem or severance tax with respect to production and sale of oil or natural gas within its jurisdiction.

The increasing regulatory burden on the oil and natural gas industry will most likely increase our cost of doing business and may affect our production rates. However, these burdens generally do not affect us differently or to any greater or lesser extent than they affect others in our industry with similar types, quantities and locations of production. Additional proposals or proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission ("FERC"), and the courts. Implementation of such could increase the regulatory burden and potential for financial sanctions for non-compliance. Although we believe we are currently in substantial compliance with all applicable laws and regulations, because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. We may be required to make significant expenditures to comply with governmental laws and regulations, which could have a material adverse effect on our business, financial condition and results of operations.

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 ("NGPA"), and the regulations promulgated thereunder by the FERC. In the past, the federal government has regulated the prices at which oil and gas could be sold. Deregulation of wellhead sales in the natural gas industry began with the enactment of the NGPA. In 1989, the Natural Gas Wellhead Decontrol Act was enacted, removing both price and non-price controls from natural gas sold in "first sales" no later than January 1, 1993. While sales by producers of natural gas, and all sales of crude oil, condensate and natural gas liquids currently can be made at uncontrolled market prices, Congress could reenact price controls in the future.

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

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

In August 2005, Congress enacted the Energy Policy Act of 2005 ("EPAct 2005"). Among other matters, the EPAct 2005 amends the Natural Gas Act ("NGA"), to make it unlawful for "any entity," including otherwise non-jurisdictional producers such as us to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. On January 20, 2006, the FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit any such statement necessary to make the statements not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1,000,000 per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sale or gathering, but does apply to activities or otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction which includes the reporting requirements under Order Nos. 704 and 720. It therefore reflects a significant expansion of FERC's enforcement authority. We have not been affected differently than any other producer of natural gas by this act.

Environmental Matters

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

- require the acquisition of permits or other authorizations before construction, drilling and certain other of our activities;
- limit or prohibit construction, drilling and other activities on specified lands within wetlands, endangered species habitat, wilderness and other protected areas; and
- impose substantial liabilities for pollution that may result from our operations;
- require the installation of pollution control equipment in connection with operations;
- place restrictions or regulations upon the use or disposal of the material utilized in on our operations;
- restrict the types, quantities and concentrations of various substances that can be released into the environment or used in connection with drilling, production and transportation activities;
- require remedial measures to mitigate pollution from former and ongoing operations, such as site restoration, pit closure and plugging of abandoned wells; and
- require the expenditure of significant amounts in connection with worker health and safety.

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

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

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

The Comprehensive Environmental, Response, Compensation, and Liability Act, as amended ("CERCLA"), and comparable state statutes impose strict liability on owners and operators of sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at these sites. This liability may be joint and several and includes liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment.

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

The Federal Water Pollution Control Act (the "Clean Water Act"), and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The EPA and delegated states have adopted regulations concerning the discharge of storm water runoff. These regulations require covered facilities to obtain individual permits or to seek coverage under a general permit. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The Clean Water Act also prohibits the unpermitted discharge of fill material into waters of the United States, including certain wetlands. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

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

The federal Clean Air Act, and comparable state laws, regulates emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. In April 2012, the EPA issued a final rule under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPs, programs. The rule establishes NSPS for certain wells, storage vessels, pneumatic controllers, compressors, and natural gas processing plants and revises the NESHAP for glycol dehydration units. This rule also requires all new hydraulically fractured wells and wells that are refractured to reduce emissions of Volatile Organic Compounds through "green completions." The rule does, however, provide a transition period that ends January 1, 2015, during which operators will have the option of flaring emissions instead of using "green completion" technologies. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Clean Air Act and associated state laws and regulations.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly reporting, waste handling, storage, transport, disposal, or cleanup requirements could materially adversely affect our operations and financial position, as well as those of the oil and gas industry in general. For example, recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to such studies, the U.S. Congress has from time to time considered climate change-related legislation to restrict greenhouse gas emissions. The ultimate outcome of this legislative initiative remains uncertain. Almost half of the states have passed laws, adopted regulations or undertaken regulatory initiatives to reduce the emission of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Although it is not possible at this time to predict whether or when the U.S. Congress may act on climate change legislation 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 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 allowed 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 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. On November 9, 2010 the EPA expanded its greenhouse reporting rule to include onshore petroleum and natural gas production, processing, transmission, storage, and distribution facilities. Under these rules, reporting of greenhouse gas emissions from such facilities is required on an annual basis, and the first reports became due in September 2012 for emissions occurring in 2011.

In addition to federal laws and regulations, the various states where we operate have enacted their own environmental laws and regulations. As an example, in 2012, Pennsylvania enacted legislation, known as Act 13, which established more stringent environmental standards. Among other changes, Act 13 required disclosure of chemicals used in hydraulic fracturing, extended the setback requirements for unconventional wells, restricted well site locations in certain areas such as floodplains, established new spill containment requirements, and authorized local governments to adopt impact fees.

Although it is not possible at this time to predict whether proposed federal or state 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.

Available Information

We maintain an internet website under the name "www.rexenergy.com." We make available, free of charge, on our website, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after providing such reports to the Securities and Exchange Commission ("SEC"). Our Corporate Governance Policy, the charters of the Audit Committee, the Compensation Committee and the Nominating and Governance Committee, and the Code of Ethics for directors, officers, employees and financial officers are also available on our website and in print to any stockholder who provides a written request to the Corporate Secretary at 476 Rolling Ridge Drive, Suite 300, State College, PA 16801. Information contained on or connected to our website is not incorporated by reference into this report and should not be considered part of this report or any other filing that we make with the SEC.

We file annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934, as amended. The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including Rex Energy Corporation, that file electronically with the SEC. The public can obtain any document we file with the SEC at www.sec.gov.

ITEM 1A. RISK FACTORS

In evaluating our company, the factors described below should be considered carefully. The occurrence of one or more of these events could significantly and adversely affect our business, prospects, financial condition, results of operations and cash flows. In such a case, you may lose all or part of your investment. The risks described below are not the only ones we face. Additional risks and uncertainties not currently known to us or those we currently view to be immaterial may also materially adversely affect our business, financial condition and results of operations.

Risks Related to Our Company

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

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

Furthermore, oil and natural gas prices continued to be volatile in 2012. For example, the NYMEX oil prices in 2012 ranged from a high of $109.77 to a low of $77.69 per Bbl and the NYMEX natural gas prices in 2012 ranged from a high of $3.90 to a low of $1.91 per MMBtu.

Lower oil, NGL and natural gas prices may not only decrease our revenues on a per unit basis, but also may reduce the amount of oil, NGLs 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, NGL 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.

Drilling for and producing oil, NGLs 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, NGL 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, NGL 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. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves. Please see below for a discussion of the uncertainties involved in these processes. Our costs of drilling, completing and operating wells are often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures could be materially and adversely affected by any factor that may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- 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, discharges of toxic gases or mishandling of fluids (including frac fluids) and underground migration issues;
- 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.

Prospects that we decide to drill may not yield oil, NGLs 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, NGLs 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, NGLs or natural gas will be present or, if present, whether oil, NGLs 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.

Our estimated proved 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 proved reserve 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, NGL and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil, NGL 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 estimated proved reserves to reflect production history, results of exploration and development, prevailing oil, NGL and natural gas prices and other factors, many of which are beyond our control.

The present value of future net cash flows from out estimated proved reserves is not necessarily the same as the current market value of our estimated oil, NGL and natural gas reserves.

We base the estimated discounted future net cash flows from our estimated 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 estimated 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.

Our development and exploration operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms or at all, 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. For 2013, we have budgeted $250.0 million for capital expenditures for development and exploration activities in the Appalachian and Illinois Basins. To date, we have financed capital expenditures primarily with proceeds from bank borrowings, cash generated by operations, public stock offerings, sales of non-core assets and joint venture agreements.

We intend to finance our future capital expenditures with proceeds from bank borrowings, the sale of debt or equity securities, asset sales, cash flow from operations and current and new financing arrangements, such as joint ventures; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. Additional borrowings under our credit facility or the issuance of additional debt securities will require that a greater portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. In addition, our credit facility imposes certain limitations on our ability to incur additional indebtedness other than indebtedness under our credit facility. If we desire to issue additional debt securities other than as expressly permitted under our credit facility, we will be required to seek the consent of the lenders in accordance with the requirements of the credit facility, which consent may be withheld by the lenders at their discretion. If we incur certain additional indebtedness, our borrowing base under our credit facility may be reduced. Also, our revolving credit contains covenants that restrict our ability to, among other things, materially change our business, approve and distribute dividends, enter into transactions with affiliates, create or acquire additional subsidiaries, incur indebtedness, sell assets, make loans to others, make investments, enter into mergers, incur liens, and enter into agreements regarding swap and other derivative transactions.

Our cash flow from operations and access to capital is subject to a number of variables, including:

- our estimated proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- our ability to extract NGLs from the natural gas we produce;
- the prices at which oil, NGLs 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, NGL and natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may need to seek additional financing in the future. In addition, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves.

We have substantial indebtedness and may incur substantially more debt, which could exacerbate the risks associated with our indebtedness.

We had approximately $250.9 million of outstanding indebtedness at December 31, 2012. We and our subsidiaries may be able to incur substantial additional indebtedness in the future, including under our revolving credit facility and our second lien credit facility. At December 31, 2012, our $500 million revolving credit facility had a borrowing base of $240.0 million for secured borrowings, subject to periodic borrowing base redeterminations.

As a result of our indebtedness, we will need to use a portion of our cash flow to pay interest, which will reduce the amount we will have available to fund our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Our indebtedness under our senior credit facility is at a variable interest rate, and so a rise in interest rates will generate greater interest expense to the extent we do not have applicable interest rate fluctuation hedges. The amount of our debt may also cause us to be more vulnerable to economic downturns and adverse developments in our business.

We may incur substantially more debt in the future. The indenture governing our senior notes contains restrictions on our incurrence of additional indebtedness. These restrictions, however, are subject to a number of qualifications and exceptions, and under certain circumstances, we could incur substantial additional indebtedness in compliance with these restrictions. Moreover, these restrictions do not prevent us from incurring obligations that do not constitute indebtedness under the indenture.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or sell additional equity on terms that we may not find attractive if it may be done at all. Further, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under that indebtedness, which could adversely affect our business, financial condition and results of operations.

Our revolving credit facility contains, and the indenture governing our senior notes contain, operating and financial restrictions that may restrict our business and financing activities.

Our revolving credit facility contains, the indenture governing our senior notes contain, and any future indebtedness we incur may contain, a number of restrictive covenants that will impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- sell assets, including equity interests in our subsidiaries;
- pay distributions on, redeem or repurchase our common stock or redeem or repurchase our subordinated debt;
- make investments;
- incur or guarantee additional indebtedness or issue preferred stock;
- create or incur certain liens;
- make certain acquisitions and investments;
- redeem or prepay other debt;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets; and
- engage in transactions with affiliates.

As a result of these covenants, we will be limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

Our ability to comply with some of the covenants and restrictions contained in our revolving credit facility and the indenture governing our senior notes may be affected by events beyond our control. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. A failure to comply with the covenants, ratios or tests in our revolving credit facility, the indenture governing our senior notes or any future indebtedness could result in an event of default under our revolving credit facility, the indenture governing our senior notes or our future indebtedness, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations. If an event of default under our revolving credit facility occurs and remains uncured, the lenders thereunder:

- would not be required to lend any additional amounts to us;

- could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be due and payable;
- may have the ability to require us to apply all of our available cash to repay these borrowings; or
- may prevent us from making debt service payments under our other agreements.

A payment default or an acceleration under our revolving credit facility could result in an event of default and an acceleration under the indenture for our senior notes.

If the indebtedness under the notes were to be accelerated, there can be no assurance that we would have, or be able to obtain, sufficient funds to repay such indebtedness in full. In addition, our obligations under our revolving credit facility are collateralized by perfected first priority liens and security interests on substantially all of our assets and if we are unable to repay our indebtedness under the revolving credit facility, the lenders could seek to foreclose on our assets.

The development of our proved undeveloped reserves in our areas of operation may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.

Approximately 58.3% of our total estimated proved reserves were classified as proved undeveloped as of December 31, 2012. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling. Our reserve data assumes that we can and will make these expenditures and conduct these operations successfully. These assumptions, however, may not prove correct. We estimate that approximately $323.2 million in capital expenditures will be required over the next five years to develop our total proved undeveloped reserves. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our estimated proved reserves as unproved reserves. Any such writeoffs of our reserves could reduce our ability to borrow money and could reduce the value of our securities.

Our identified drilling locations are scheduled to be drilled over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling

Our management has identified and scheduled drilling locations as an estimate of our future multi- year drilling activities on our existing acreage. All of our drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, availability of drilling services and equipment, lease expirations, gathering system, marketing and pipeline transportation constraints, oil and natural gas prices, drilling and production costs, drilling results and other factors. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. Pursuant to SEC rules and guidance, 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. The SEC rules and guidance may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program.

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

Producing oil, NGLs and natural gas reservoirs generally are characterized by declining production rates that vary depending on reservoir characteristics and other factors. Our future oil, NGL 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.

If we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules, our ability to produce gas commercially and in commercial quantities could be impaired.

We use between four and six million gallons of water per well in our well completion operations in the Appalachian Basin. Our inability to locate sufficient amounts of water, or dispose of water after drilling, could adversely impact our operations. Moreover, the adoption and implementation of new environmental regulations could result in restrictions on our ability to conduct certain operations such as hydraulic fracturing or the imposition of new requirements pertaining to the management and disposal of wastes generated by our operations, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. Furthermore, new environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may also increase operating costs and cause delays, interruptions or termination of operations, the extent of which cannot be predicted, all of which could adversely affect our financial condition and results of operations.

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

We may, from time to time, encounter difficulty in obtaining, or an increase in the cost of securing, drilling rigs, equipment, services and supplies. In addition, larger producers may be more likely to secure access to such equipment and services by offering more lucrative terms. If we are unable to acquire access to such resources, or can obtain access only at higher prices, our ability to convert our reserves into cash flow could be delayed and the cost of producing those reserves could increase significantly, which would adversely affect our financial condition and results of operations.

Federal, state and local regulation of hydraulic fracturing could result in increased costs and additional restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We commonly use hydraulic fracturing as part of our operations. Increased regulation of hydraulic fracturing may adversely impact our business, financial condition, and results of operations. The federal Safe Drinking Water Act ("SDWA") regulates the underground injection of substances through the Underground Injection Control Program ("UIC"). The hydraulic fracturing process is typically regulated by state oil and natural gas commissions; however, the Environmental Protection Agency ("EPA") has asserted federal regulatory authority over certain hydraulic fracturing activities involving the use of diesel under the SDWA's UIC program. On May 4, 2012, the EPA issued draft guidance for SDWA UIC permits issued to oil and natural gas exploration and production operators injecting diesel fuels during the hydraulic fracturing process. In addition, legislation has been introduced in prior sessions of Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of chemicals used in the hydraulic fracturing process. Also, many state governments have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, well construction, and operational requirements on hydraulic fracturing operations or otherwise seek to temporarily or permanently ban fracturing activities. In addition to state laws, local land use restrictions, such as city ordinances, zoning laws, and traffic regulations may restrict or prohibit the performance of well drilling in general or hydraulic fracturing in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. In December 2012. the EPA issued an update stating that draft results of the study would be available for peer review in 2014. In the interim, however, the EPA has utilized existing statutory authority under the SDWA, the Clean Water Act ("CWA"), Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), and the Clean Air Act ("CAA") to investigate, order actions, and potentially pursue penalties against some oil and natural gas producers where EPA believes their activities may have impacted the air or groundwater. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. On April 13, 2012, President Obama issued an executive order creating a task force to coordinate federal oversight over domestic natural gas production and hydraulic fracturing. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

To our knowledge, there have been no citations, suits, or contamination of potable drinking water arising from our fracturing operations. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our general liability and excess liability insurance policies would cover third-party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies.

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

Market conditions or the unavailability of satisfactory oil, NGL and natural gas transportation arrangements may hinder our access to oil, NGL and natural gas markets or delay our production. The availability of a ready market for our oil, NGL and natural gas production depends on a number of factors, including the demand for and supply of oil, NGLs 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, NGLs 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 and other areas of the Appalachian Basin continues to be successful, the amount of 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 these areas may not occur. 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, which would adversely affect our results of operations.

A portion of our natural gas, NGL 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.

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

An EOR technique such as alkali-surfactant-polymer ("ASP") chemical injection involves significant capital investment and an extended period of time, generally two years or longer, from the initial phase of a pilot program until increased production occurs. The results of any successful pilot program may not be indicative of actual results achieved in a broader EOR project in the same field or area. Generally, surfactant polymer, including ASP, injection is regarded as involving more risk than traditional waterflood operations. Our ability to achieve commercial production and recognize estimated proved reserves from our EOR projects is greatly contingent upon many inherent uncertainties associated with EOR technology, including ASP technology, geological uncertainties, chemical and equipment availability, rig availability and many other factors.

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

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

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

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

For the year ended December 31, 2012, approximately 82.4% of our net production came from the Appalachian Basin and 17.6% came from the Illinois Basin. As of December 31, 2012, approximately 91.1% of our estimated proved reserves were located in the fields that comprise the Appalachian Basin and 8.9% of our estimated proved reserves were located in fields that comprise the Illinois Basin. If mechanical problems, weather conditions or other events were to curtail a substantial portion of the production in one or both of these regions, our cash flow would be adversely affected. If ultimate production associated with these properties is less than our estimated reserves, or changes in pricing, cost or recovery assumptions in the area results in a downward revision of any estimated reserves in these properties, our business, financial condition and results of operations could be adversely affected.

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

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

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

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

We review our oil and gas properties for impairment 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 gas or oil prices increase. Given the complexities associated with oil and gas reserve estimates and the history of price volatility in the oil and gas markets, events may arise that would require us to record an impairment of the book values associated with oil and gas properties.

Additional 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.

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

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

Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition and results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil, NGLs 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 and soil 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 financial condition, results of operations and cash flows.

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

The exploration, development, production and sale of oil, NGLs and natural gas are subject to extensive federal, state, and local laws and regulations. Such regulation includes requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling and well operations. Other activities subject to regulation are:

- the location and spacing of wells;
- the unitization and pooling of properties;
- the method of drilling and completing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells;
- the disposal of fluids used or other wastes generated in connection with our drilling operations;
- the marketing, transportation and reporting of production; and
- the valuation and payment of royalties.

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

We must obtain governmental permits and approvals for our drilling and midstream 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 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 natural gas or oil 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, NGL and natural gas operations are subject to stringent federal, state and local laws and regulations governing the release of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of substances that can be released into the environment in connection with our drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, including the habitat of threatened and endangered species, 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 the issuance of injunctions restricting or prohibiting certain activities. 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 whether 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.

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

In December 2009, the EPA published its findings that emissions of greenhouse gases ("GHGs") present a danger to public 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 conditions. Based on these findings, in 2010 the EPA adopted two sets of regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act, including one that requires a reduction in emissions of GHGs from motor vehicles and another that requires certain construction and operating permit reviews for GHG emissions from certain large stationary sources. The stationary source final rule addresses the permitting of GHG emissions from stationary sources under the Clean Air Act Prevention of Significant Deterioration, or PSD, construction and Title V operating permit programs, pursuant to which these permit programs have been "tailored" to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting.

In addition, in November 2010, the EPA issued a final rule requiring companies to report certain greenhouse gas emissions from oil and natural gas facilities. On July 19, 2011, the EPA amended the oil and natural gas facility greenhouse gas reporting rule to require reporting. Under this rule, initial reports became due in September 2012. We believe that we are in substantial compliance with these reporting obligations. The EPA has indicated that it will use GHG reporting data in considering whether to initiate further rulemaking to establish GHG emissions limits. Further, in April 2012 the EPA issued final New Source Performance Standards and National Emission Standards for Air Pollutants. This rule requires all new hydraulically fractured wells to reduce emissions of Volatile Organic Compounds through "green completions." The rule is designed to reduce GHG emissions during well completions. The rule does, however, provide a transition period that ends January 1, 2015, during which operators will have the option of flaring emissions instead of using "green completion" technologies. Also, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states already have taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise restricts emissions of GHGs from our equipment and operations could require us to incur significant added costs to reduce emissions of GHGs or could adversely affect demand for the oil, natural gas and NGLs we produce. Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate change that could have significant physical effect, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if such effects were to occur, they could have an adverse effect on our assets and operations.

The adoption of derivatives legislation by Congress and related regulations could have an adverse impact on our ability to use derivative instruments, particularly swaps, to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Act, was enacted in 2010. The Act provides for new statutory and regulatory requirements for derivative transactions, including certain oil and gas hedging transactions involving swaps. In particular, the Act includes a requirement that certain hedging transactions involving swaps be cleared and exchange-traded and a requirement to post cash collateral for non-cleared swap transactions, although, at this time, it is unclear which transactions will ultimately be required to be cleared and exchange-traded or which counterparties will be required to post cash collateral with respect to non-cleared swap transactions. The Act provides for a potential exception from the clearing and exchange-trading requirement for hedging transactions by commercial end-users, a category of non-financial entities in which we may be included. While the Commodity Futures Trading Commission, or CFTC, and other federal agencies have adopted, and continue to adopt, numerous regulations pursuant to the Act, many of the key concepts and defined terms under the Act have not yet been delineated by rules and regulations to be adopted by the CFTC and other applicable regulatory agencies. As a consequence, it is difficult to predict the aggregate effect the Act and the regulations promulgated thereunder may have on our hedging activities. Whether we are required to submit our swap transactions for clearing or post cash collateral with respect to such transaction will depend on the final rules and definitions adopted by the CFTC. If we are subject to such requirements, significant liquidity issues could result by reducing our ability to use cash posted as collateral for investment or other corporate purposes. A requirement to post cash collateral could also limit our ability to execute strategic hedges, which would result in increased commodity price uncertainty and volatility in our future cash flows. The Act and related regulations will also require us to comply with certain futures and swaps position limits and new recordkeeping and reporting requirements, and may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The Act and related regulations could also materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

Enactment of a Pennsylvania severance tax and impact fees on natural gas could adversely impact our results of existing operations and the economic viability of exploiting new gas drilling and production opportunities in Pennsylvania.

While Pennsylvania has historically not imposed a severance tax (relating to the extraction of natural gas), with a focus on its budget deficit and the increasing exploration of the Marcellus Shale, various legislation has been proposed since 2008. In February 2012, Pennsylvania implemented an impact fee. This new law imposed an impact fee on all unconventional wells drilled in the Commonwealth of Pennsylvania in counties that elected to impose the fee. The fee, which changes from year to year, is based on the average annual price of natural gas as determined by the NYMEX price, as reported by the Wall Street Journal for the last trading day of each calendar month. Based upon natural gas prices for 2012, operators will pay $45,000 per unconventional horizontal well. Unconventional vertical wells will pay a fee equal to twenty percent of the horizontal well fee and the impact fee will not apply to any unconventional vertical well that produces less than 90 Mcf per day. The payment structure for the impact fee makes the fee due the year after an unconventional well is spudded and the fee will continue for 15 years for a horizontal well and 10 years for a vertical well.

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 continue to experience the after-effects of a global recession and credit market crisis. More volatility may occur before a sustainable growth rate is achieved either domestically or globally. Even if such growth rate is achieved, such a rate may be lower than the U.S. and international economies have experienced in the past. 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, NGL and natural gas production as well as lower commodity prices, which will reduce our cash flows from operations and our profitability.

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

We have entered into, and we expect to enter into in the future, oil and gas financial derivative arrangements corresponding to a significant portion of our oil and natural gas production. Many derivative instruments that we employ require us to make cash payments to the extent the applicable index exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in oil and natural gas prices. We received net payments of $16.2 million in relation to our commodity derivative instruments for the year ended December 31, 2012.

If our actual production and sales for any period are less than the corresponding volume of derivative contracts for that period (including reductions in production due to operational delays), or if we are unable to perform our activities as planned, we might be forced to satisfy all or a portion of our derivative obligations without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. In addition, our oil and gas financial derivative activities can result in substantial losses. Such losses could occur under various circumstances, including any circumstance in which a counterparty does not perform its obligations under the applicable derivative arrangement, the arrangement is imperfect or our derivative policies and procedures are not followed or do not work as planned. Under the terms of our revolving 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.

The Standardized Measure and PV-10 of our estimated reserves are not accurate estimates of the current fair value of our estimated proved oil and natural gas reserves.

Standardized Measure is a reporting convention that provides a common basis for comparing oil and natural gas companies subject to the rules and regulations of the SEC. Our non-GAAP financial measure, PV-10, is a similar reporting convention that we have disclosed in this report. Both measures require the use of operating and development costs prevailing as of the date of computation. Consequently, they will not reflect the prices ordinarily received or that will be received for oil and natural gas production because of varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and natural gas properties. Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. In addition, the 10 percent discount factor, which is required by the rules and regulations of the SEC to be used in calculating discounted future net cash flows for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our company or the oil and natural gas industry in general. Therefore, Standardized Measure or PV-10 included in this report should not be construed as accurate estimates of the current fair value of our proved reserves.

Based on December 31, 2012 reserve estimates, we project that a 10% decline in the price per barrel of oil, price per barrel of NGLs and the price per Mcf of gas from average 2012 prices would reduce our gross revenues, before the effects of derivatives, for the year ending December 31, 2013 by approximately $15.5 million.

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 sales to a relatively small number of purchasers. Approximately 95.3% of our commodity sales from continuing operations as of December 31, 2012 were due from five customers, with the largest single customer accounting for 48.1%. If we were unable to continue to sell our oil, NGLs, or natural gas to these key customers, or to offset any reduction in sales to these customers by additional sales to our other customers, it 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.

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.

Our future acquisitions may yield revenue or production that varies significantly from our projections.

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

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.

Congress has recently considered, is considering, and may continue to consider, legislation that, if adopted in its proposed or similar form, would deprive some companies involved in oil and natural gas exploration and production activities of certain U.S. federal income tax incentives and deductions currently available to such companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures.

It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective and whether such changes may apply retroactively. Although we are unable to predict whether any of these or other proposals will ultimately be enacted, the passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available to us, and any such change could negatively affect our financial condition and results of operations.

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.

The outcome of litigation in which we have been named as a defendant is unpredictable and an adverse decision in any such matter could have a material adverse effect on our financial position.

We are defendants in a number of litigation matters and are subject to various other claims, demands and investigations. These matters may divert financial and management resources that would otherwise be used to benefit our operations. No assurances can be given that the results of these matters will be favorable to us. An adverse resolution or outcome of any of these lawsuits, claims, demands or investigations could have a negative impact on our financial condition, results of operations and liquidity.

Risks Related to Our Common Stock

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

In the future we may issue our previously authorized and unissued securities, 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 100,000,000 shares of common stock and 100,000 shares of preferred stock with such designations, preferences, and rights as may be determined by our board of directors. As of March 7, 2013, there were 53,228,771 shares of our common stock issued and outstanding and there were no shares of our 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 future public offerings, the hiring of personnel, future acquisitions, future private placements of our securities for capital raising purposes or for other business purposes. 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.

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 Chairman and other executive officers, who collectively beneficially own approximately 15% of the outstanding shares of our common stock as of March 7, 2013.

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 March 7, 2013, our board of directors, including Lance T. Shaner, our Chairman, and our other executive officers collectively own approximately 15% 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 Chairman and other executive officers, could discourage potential takeover attempts and could reduce the price that investors might be willing to pay for shares of our common stock.

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

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

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 preferred stock, it may adversely affect the market price of our common stock.

Substantial sales of our common stock could cause our stock price to decline.

If our stockholders sell a substantial number of shares of our common stock, or the public market perceives that our stockholders might sell shares of our common stock, the market price of our common stock could decline significantly. We cannot predict the effect that future sales of our common stock or other equity-related securities by our stockholders would have on the market price of our common stock.

ITEM 1B. UNRESOLVED STAFF COMMENTS

As of the date of this filing, we have no unresolved comments from the staff of the SEC.

ITEM 2. PROPERTIES

The table below summarizes certain data for our core operating areas at December 31, 2012:

	Average Daily Production (Mcfe per day)	Total Production (Mcfe)	Percentage of Total Production	Total Estimated Proved Reserves (Mcfe)	Percentage of Total Estimated Proved Reserves
Appalachian Basin	55,307	20,242,244	82.4%	563,135,900	91.1%
Illinois Basin	11,790	4,315,146	17.6%	54,914,100	8.9%
Total	67,097	24,557,390	100.0%	618,050,000	100.0%

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

Appalachian Basin

As of December 31, 2012, we owned an interest in approximately 513 producing natural gas wells in the Appalachian Basin, located predominantly in Pennsylvania and Ohio. In addition to our producing wells in the basin, we own 99.0 gross PUD drilling locations with total reserves of 359.9 Bcfe, and one location with proved developed non-producing reserves totaling 3.4 Bcfe. At December 31, 2012, we had approximately 177,200 gross (103,100 net) acres in the Appalachian Basin under lease, of which 110,200 gross (70,700 net) acres were undeveloped. Of our total acreage holdings in the Appalachian Basin, we believe that approximately 69,400 gross (48,400 net) acres are prospective for Marcellus, Utica and Upper Devonian production.

Reserves at December 31, 2012 increased 246.0 Bcfe, or 77.6%, from 2011 due primarily to our successful drilling and exploration activities in addition to estimated proved reserves related to future ethane sales, which we did not have prior to 2012. During 2012, we entered into certain processing and transportation agreements that will allow us in the future to extract ethane from our produced natural gas and sell it as a separate product. Annual production increased 101.2% over 2011.

Capital expenditures in 2012 for drilling and facility development totaled $147.1 million, which funded the drilling of 30.0 gross (20.6 net) wells. During the year, we placed into service 24.0 gross (15.7 gross) wells and had an inventory of 29.0 gross (18.8 net) wells awaiting completion or a pipeline connection. Our plans for 2013 have allocated approximately $200.0 million in capital expenditures to our Marcellus, Utica and Burkett Shale project areas.

Marcellus Shale

As of December 31, 2012, we had interests in approximately 128,000 gross (70,500 net) Marcellus Shale prospective acres in areas of Pennsylvania, and we continue to expand our position by strategically filling in key pieces of acreage to complete drilling units.

On September 30, 2010, we entered into a joint venture transaction with Summit Discovery Resources II, LLC and Sumitomo Corporation, whom we collectively refer to herein as "Sumitomo". In Butler, Beaver and Lawrence counties, Pennsylvania we sold a 15% non-operated interest in approximately 41,000 net acres for approximately $30.6 million in cash at closing and $30.6 million in the form of a drilling carry of 80% of our drilling and completion costs in the area. Pursuant to the Participation and Exploration Agreement (the "Sumitomo PEA"), Sumitomo agreed to pay all costs to lease approximately 9,000 acres in the Butler County Area of Mutual Interest ("AMI") (the "Phase I Leasing"), and was obligated to pay to us a lease management fee of $1,000 per net acre during the Phase I Leasing. Under the Sumitomo PEA, upon the conclusion of Phase I Leasing, we were required to cross assign interests in the leases with Sumitomo to provide uniformity of interest in each lease in the Butler County AMI. The Phase I Leasing Project was completed in 2011, with the final ownership percentages in the Butler County AMI being approximately 70% to us and 30% to Sumitomo. In addition to the sale of undeveloped acreage, we also sold to Sumitomo 30% of our then-held interests in 20 Marcellus Shale wells within the Butler County AMI and 30% of our interest in Keystone Midstream Services, LLC. As discussed below, we sold our interest in Keystone Midstream Services, LLC in May 2012.

In our Marcellus Shale joint venture project area with WPX Energy San Juan, LLC and Williams Production Appalachia, LLC (collectively, "WPX") (entered into in 2009), in Westmoreland and Clearfield Counties, Pennsylvania, we sold to Sumitomo 20% of our interests in 21,000 net acres for approximately $19.0 million in cash at closing and $19.0 million in the form of a drilling carry of 80% of our drilling and completion costs in the project area. In addition, we sold 20% of our interests in 19 Marcellus Shale wells located in the WPX joint venture areas and 20% of our interest in RW Gathering, LLC, a midstream joint venture with WPX. The resulting working interest ownership is 50% WPX, 40% Rex Energy and 10% Sumitomo.

In addition to the areas above, we sold to Sumitomo 50% of our interests in approximately 4,500 net acres in Fayette and Centre Counties, Pennsylvania for $9.2 million in cash at closing and $9.2 million in the form of a drilling carry of 80% of our drilling and completion costs. Pursuant to the Sumitomo PEA, the drilling carry for these areas was able to be applied, at our discretion, to drilling and completion costs attributable to either the Butler County or WPX Project Areas.

At closing, we received approximately $99.5 million in cash, which included a reimbursement for leasing expenses incurred subsequent to the effective date of September 1, 2010, in the amount of $7.6 million. Additionally, the cash payment included a reimbursement for drilling related expenses incurred subsequent to the effective date in the amount of approximately $7.5 million, which was applied against the drilling carry. Sumitomo met its drilling carry obligation during the first quarter of 2011.

Utica Shale

During 2012, we placed two Utica Shale wells into sales, one in Butler County, Pennsylvania and one in our Warrior North Prospect in Carroll County, Ohio. As of December 31, 2012, we had recorded approximately 8.0 Bcfe of estimated proved reserves related to our Utica Shale development, which was comprised of 53.3% liquids and 46.7% natural gas. Specific to our acreage holdings in Ohio, our estimated proved reserves are comprised of 62.2% liquids and 37.8% natural gas.

As of December 31, 2012, we had under lease approximately 112,700 gross (80,200 net) acres prospective for the Utica Shale in Ohio and Pennsylvania. In Ohio, our holdings comprise approximately 22,800 gross (20,000 net) acres which we believe to be prospective for liquids-rich production. In Pennsylvania, we estimate that much of our acreage in Butler County is prospective for dry gas Utica Shale production as well as acreage in some other non-core areas of the state. As of December 31, 2012, we estimate Utica Shale acreage holdings in Pennsylvania of approximately 89,900 gross (60,100 net) acres.

Upper Devonian

During 2012, we placed our first Burkett Shale well into sales and booked estimated proved reserves of approximately 7.7 Bcfe, comprising 43.9% liquids and 56.1% natural gas. The Burkett Shale is one of the shales that lies within the Upper Devonian formation. We estimate that much of our acreage in Butler County, Pennsylvania is prospective for wet gas Burkett Shale production. As of December 31, 2012, we estimate Upper Devonian acreage holdings of approximately 69,400 gross (48,400 net).

Illinois Basin

In the Illinois Basin, we own an interest in 1,877 wells, which includes 534 disposal and injection wells. We have approximately 64,600 (37,400 net) acres owned and under lease.

Total estimated proved reserves in the Illinois Basin increased approximately 5.8 Bcfe, or 11.9%, to approximately 54.9 Bcfe at December 31, 2012 when compared to year-end 2011, which was primarily due to the addition of 4.5 Bcfe of estimated proved developed non-producing reserves from our ASP project in the Delta Unit as a result of the success of our pilot operations in the area. Annual production increased 3.7% from 2011. Capital expenditures in 2012 for drilling, facility improvements and acreage acquisitions in the region were approximately $24.3 million, which funded the drilling of 13.0 gross (10.3 net) wells. These expenditures also covered work performed in the basin designed to optimize our secondary waterflood operations whereby we stabilized declining production. Capital expenditures for drilling and facilities development for the Lawrence Field ASP Flood Project totaled approximately $12.8 million.

Lawrence Field ASP Flood Project

We currently own and operate 21.2 square miles (approximately 13,500 net acres) of the Lawrence Field. The Cypress (Mississippian) and the Bridgeport (Pennsylvanian) sandstones are the major producing horizons in the field. To date, approximately 40% of the estimated one billion barrels of the original oil in place has been produced.

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

In the 1960s, 1970s and 1980s, a number of EOR projects using surfactant polymer floods were implemented in several fields in the Illinois Basin by Marathon, Texaco and Exxon in an attempt to recover a portion of the large percentage of the original oil in place that was being bypassed by the secondary recovery waterflood. These test projects reportedly were able to recover incremental oil reserves of 15% to 30% of the original oil in place. While we believe the results of these projects are pertinent, there can be no assurance that our Lawrence Field ASP Flood Project, which uses technology that was not developed at the time of the prior EOR projects, will achieve similar results. More modern ASP technology, which uses mechanisms to mobilize bypassed residual oil similar to these previous surfactant polymer floods but at significantly lower costs, has been applied by other companies in several fields around the world resulting in significant incremental recoveries of the original oil in place. Chemicals used in the Lawrence Field ASP Flood Project include alkali, surfactants and polymer. The alkali and surfactant combination acts like a soap and washes residual oil from the reservoir mainly by reducing interfacial tension between the oil and the water. The polymer is added to improve sweep displacement efficiency by pushing the "washed" oil through the rock pores of the reservoir.

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

In 2000, PennTex Resources Illinois, Inc., one of our predecessor companies, then known as Plains Illinois, Inc., and the U.S. Department of Energy conducted a study on the potential of an ASP project in the Lawrence Field, with consulting services provided by an independent engineering firm specializing in the design and implementation of chemical oil recovery systems. Based on the modeling of the reservoir characteristics and laboratory tests with cores taken in the Lawrence Field, the evaluation found oil recovery in the field could be increased significantly by installing an ASP flood. However, there can be no assurance that our Lawrence Field ASP Flood Project will achieve similar results to those conducted in the study.

During 2008 and 2009, we completed two four acre pilot tests, one each in the Bridgeport and Cypress sandstones. Both of the pilots demonstrated a response to the chemical injection, as indicated by an increase in both oil production and the oil cut ratio. Each pilot area had individual wells whose oil cut exceeded 10% after the initial response; whereas the oil cuts for both pilots at the time ASP injection was initiated were less than 1%. During 2010, we commenced chemical injection into our 15-acre Middagh ASP pilot unit and received initial and peak response during 2011, with oil cuts increasing from 1% to approximately 12%, and several wells peaking at an oil cut of 17%. Production has since begun its gradual decline; however the successful response from this project resulted in the assignment of 874.0 MBbls of estimated proved reserves as of December 31, 2012. Approximately 758.3 MBls of estimated proved reserves are attributable to our Delta Unit. We are continuing to move forward with ASP expansion with the 58-acre Perkins-Smith project area. ASP injection into the Perkins-Smith occurred in June 2012, with initial production response expected in mid-2013 and peak production expected in the fourth quarter of 2013. In addition to the Perkins-Smith Unit, we have completed the drilling and infrastructure construction phase of our commercial size Delta Unit with ASP injection expected to commence during the fourth quarter of 2013.

We are in the process of identifying the next ASP flood units in the Bridgeport and Cypress sands. Depending on the size of each flood unit, it is anticipated that initial response time from the chemical injection date will be approximately 10 to 12 months and the time to peak response will be approximately 24 to 30 months.

Estimated Proved Reserves

For estimated proved reserves as of December 31, 2012, proved locations were identified, assessed and justified using the evaluation methods of performance analysis, volumetric analysis and analogy. In addition, reliable technologies were used to support a select number of undeveloped locations in the Marcellus Shale Region. Within the Marcellus Shale Region, we used both public and proprietary geologic data to establish continuity of the formation and its producing properties. This data included performance data, seismic data, micro-seismic analysis, open hole log information and petro-physical analysis of the log data, mud logs, log cross-sections, gas sample analysis, drill cutting samples, measurements of total organic content, thermal maturity and statistical analysis. In our development area, these data demonstrated consistent and continuous reservoir characteristics.

The following table sets forth our estimated proved reserves as defined in Rule 4.10(a) of Regulation S-X and Item 1200 of Regulation S-K:

	Net Reserves		
Category	**Oil (Barrels)**	**NGLs (Barrels)**	**Gas (Mcf)**
Proved Developed	8,380,400	10,066,900	138,772,500
Proved Developed Non-Producing	835,700	76,800	2,982,100
Proved Undeveloped	159,700	21,536,200	229,961,200
Total Proved	9,375,800	31,679,900	371,715,800

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, 2012 in conjunction with our reserve estimates.

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

	2012	2011	2010
Description			
Proved Developed Reserves			
Oil (Bbls)	9,216,100	8,181,200	8,142,779
Natural Gas (Mcf)	141,754,600	110,853,300	32,477,226
NGLs (Bbls)	10,143,700	2,218,420	656,326
Proved Undeveloped Reserves			
Oil (Bbls)	159,700	—	—
Natural Gas (Mcf)	229,961,200	163,439,000	95,144,609
NGLs (Bbls)	21,536,200	4,916,380	3,543,723
Total Estimated Proved Reserves (Mcfe)[1, 2, 3]	618,050,000	366,188,300	201,678,803
PV-10 Value (millions)[2, 4]	$ 500.5	$ 539.6	$ 269.4
Standardized Measure (millions)[2]	$ 396.1	$ 413.9	$ 188.1

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, 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 Totals of estimated proved reserves, PV-10 Value and Standardized Measure exclude values from our DJ Basin properties which are classified as Held for Sale on our Consolidated Balance Sheet at December 31, 2011 and 2012.

3 We converted crude oil and NGLs to Mcf equivalent at a ratio of one barrel to six Mcfe.

4 PV-10, a non-GAAP measure, represents the present value, discounted at 10% per annum of estimated future cash flows of our estimated proved reserves before income tax and asset retirement obligations. The estimated future cash flows set forth above were determined by using reserve quantities of estimated 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 2012, using $90.92 per barrel of oil, $32.91 per barrel of NGLs and $2.941 per Mcf of natural gas, as adjusted by lease for transportation fees and regional price differentials. Management believes that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. For an explanation of why we show PV-10 and a reconciliation of PV-10 to the standardized measure of discounted future net cash flow, please read "Item 6. Selected Historical Financial and Operating Data—Non-GAAP Financial Measures." Please also 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."

Proved Undeveloped Reserves (PUDs)

As of December 31, 2012, our PUD reserves totaled 0.2 MMBOE of oil, 21.5 MMBOE of NGLs and 230.0 Bcf of natural gas, for a total of 360.1 Bcfe. The majority of our PUDs at year-end 2012 were associated with the Appalachian Basin. All of these projects will have PUDs convert from undeveloped to developed as these projects begin production and/or production facilities are expanded or upgraded. Changes in PUDs that occurred during the year were due to:

- conversion of approximately 45.6 Bcfe attributable to PUDs into proved developed reserves;
- 173.6 Bcfe in PUDs due to extensions and discoveries, which are primarily related to the extension of proved acreage in areas that are prospective for the Marcellus, Utica and Upper Devonian (Burkett) Shale, through our drilling activities. During 2012, we drilled approximately 10.0 gross (6.5 net) wells that were not considered proved in addition to 17.0 gross (10.5 net) wells that were classified as PUDs as of December 31, 2011.

Costs incurred relating to the development of 17.0 gross (10.5 net) PUD locations to proved developed were approximately $33.7 million in 2012. Estimated future development costs relating to the development of our 100.0 gross (63.9 net) PUDs are projected to be approximately $50.3 million in 2013, $61.3 million in 2014, $95.2 million in 2015, $60.5 million in 2016 and $55.9 million in 2017.

Most PUD drilling locations are scheduled to be drilled prior to the end of 2017, including approximately 14.0% of the total in 2013. Initial production from these PUD locations is expected to begin between 2013 and 2018. Approximately 33.0 gross (20.1 net) PUD locations were booked based on reliable technology. We have approximately two gross (1.1 net) PUD locations that are to be developed more than five years after first booking. These wells are a part of a development program which includes multiple wells from the same pad that has been pushed outside of the five year range due to our current strategy of drilling single well pads to hold acreage. In addition to holding acreage, it is our plan to develop our PUD reserves in a manner consistent with the five-year rule for PUD locations. The wells that are to be developed outside of the five years from first booking are on pad drilling sites that have additional PUD locations which are currently scheduled to be developed within five years of first booking. We intend to develop these PUD locations, regardless of first booking date, in a pad development mode. We believe that this strategy allows for the wells to remain classified as PUD locations. A total of 6.3 Bcfe of estimated proved reserves are attributed to these wells or approximately 1.7% of our total estimated proved undeveloped reserves.

The following table summarizes the changes in our proved undeveloped reserves for the year ended December 31, 2012:

Proved Undeveloped Reserves (Mcfe)	**For the Year Ended December 31, 2012**
Beginning proved undeveloped reserves	192,937,600
Undeveloped reserves converted to developed	(45,561,700)
Revisions	39,191,500
Extensions and discoveries	173,569,200
Ending proved undeveloped reserves	360,136,600

Reserve Estimation

Netherland, Sewell & Associates, Inc. ("NSAI"), an independent petroleum engineering firm, evaluated our reserves on a consolidated basis as of December 31, 2012. At December 31, 2012, these consultants collectively reviewed all of our estimated proved reserves. A copy of the summary reserve report is included as Exhibit 99.1 to this Annual Report on Form 10-K. The technical persons responsible for preparing our estimated proved reserves estimates meet the requirements with regards 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. Our independent third-party engineers do 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 NSAI to ensure the integrity, accuracy and timeliness of the data used to calculate our estimated proved reserves. Our internal technical team members meet with NSAI periodically throughout the year to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to NSAI 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 are completed in accordance with our internal control procedures, which include documented process workflows, the verification of input data used by NSAI, as well as management review and approval.

All of our reserve estimates are reviewed and approved by our Director, Reservoir Engineering and our President and Chief Operating Officer. Our Director, Reservoir Engineering holds a Bachelor of Science degree in Petroleum Engineering from the University of Texas at Austin with more than seven years of experience in preparing reserve reports under the guidelines of the SEC with Cano Petroleum and with us. Our President and Chief Operating Officer holds a Bachelor of Science degree in Petroleum Engineering from the University of Wyoming and an M.B.A. from Pepperdine University, with approximately 25 years of experience working for companies such as Cano Petroleum, Pioneer Natural Resources and Union Pacific Resources.

Acreage and Productive Wells Summary

The following table sets 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, 2012:

	Undeveloped Acreage[1]		Developed Acreage[2]		Total Acreage		Producing Gas Wells		Producing Oil Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Appalachian Basin										
Pennsylvania	88,800	51,800	65,700	31,300	154,500	83,100	532	245	—	—
Ohio	21,500	18,900	1,300	1,100	22,800	20,000	1	1	—	—
Total Appalachian Basin	110,300	70,700	67,000	32,400	177,300	103,100	533	246	—	—
Illinois Basin[3]										
Illinois	4,100	1,400	46,100	24,300	50,200	25,700	—	—	1,141	1,132
Indiana	300	300	12,100	10,800	12,400	11,100	—	—	203	198
Kentucky	—	—	2,100	500	2,100	500	—	—	—	—
Total Illinois Basin	4,400	1,700	60,300	35,600	64,700	37,300	—	—	1,344	1,330
Total	114,700	72,400	127,300	68,000	242,000	140,400	533	246	1,344	1,330

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

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

(3) Total net acreage includes approximately 10,000 gross (10,000 net) acres that are owned by us. These acres are primarily leased to third parties and are not currently deemed as available for development.

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

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:

	Expiring Acreage	
	Gross	Net
Year Ending December 31,		
2013	17,900	7,500
2014	15,500	8,200
2015	26,800	15,900
2016	37,400	26,100
Thereafter[1]	18,300	10,400
Total	115,900	68,100

1 Will not reconcile to total undeveloped acreage due to being subject to drilling commitments and acreage that may be held by production in a legal unit but is still considered undeveloped.

The expiring acreage set forth in the tale above accounts for 64.5% our total net acreage. We are continually engaged in a combination of drilling and development and discussions with mineral lessors for lease extensions, renewals, new drilling and development units and new leases to address the expiration of undeveloped acreage that occurs in the normal course of our business.

Drilling Results

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

	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Illinois Basin[1]	12.0	9.8	6.0	3.0	14.0	10.9
Appalachian Basin	2.0	1.4	13.0	6.6	14.0	8.0
DJ Basin[2]	—	—	—	—	—	—
Non-Productive	1.0	0.5	—	—	1.0	1.0
Total Developmental Wells	15.0	11.7	19.0	9.6	29.0	19.9
Exploratory:						
Illinois Basin	—	—	—	—	—	—
Appalachian Basin	28.0	19.2	44.0	23.6	13.0	7.0
DJ Basin[2]	—	—	1.0	1.0	2.0	1.5
Non-Productive	—	—	1.0	1.0	2.0	2.0
Total Exploratory Wells	28.0	19.2	46.0	25.6	17.0	10.5
Total Wells	43.0	30.9	65.0	35.2	46.0	30.4
Success Ratio[3]	97.7%	98.4%	98.5%	97.2%	93.5%	90.1%

1 Does not include wells drilled for our ASP project, which is a longer lead time project for which results are not expected for several months.

2 DJ Basin assets are classified as held for sale.

3 Success ratio is calculated by dividing the total successful wells drilled divided by the total wells drilled.

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, we often conduct a preliminary investigation of record title and related matters at the time of lease acquisition. We conduct more comprehensive mineral title opinion reviews, topographic evaluations and infrastructure investigations 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.

ITEM 3. LEGAL PROCEEDINGS

The information set forth in Note 25, *Litigation,* in the notes to our Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Our common stock is traded on the NASDAQ Global Select Market under the symbol "REXX". As of March 7, 2013, there were approximately 109 holders of record of our common stock.

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

2012	High	Low
First Quarter	$15.32	$ 9.29
Second Quarter	11.50	8.80
Third Quarter	14.65	10.78
Fourth Quarter	14.11	11.69

2011	High	Low
First Quarter	$14.33	$10.31
Second Quarter	13.18	9.67
Third Quarter	15.64	9.96
Fourth Quarter	18.00	10.63

The closing price of our common stock on March 7, 2013 was $14.23.

Dividends

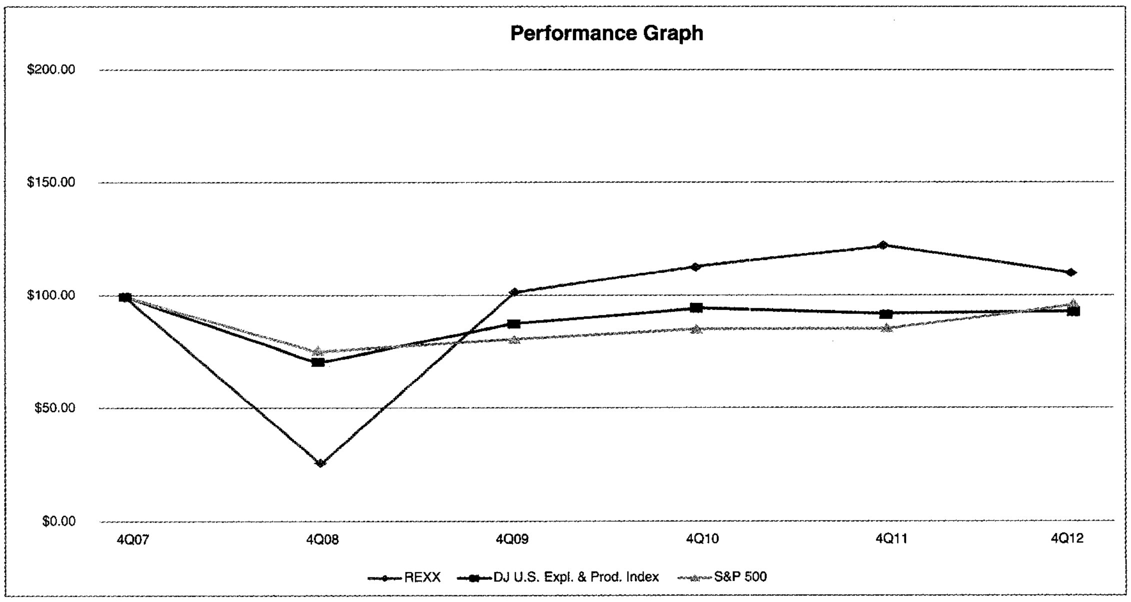
We have not paid cash dividends on our common stock since our inception in March 2007. We do not anticipate paying any dividends on the shares of our common stock in the foreseeable future. We currently intend to reinvest our earnings to finance the expansion of our business. In addition, the terms of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

Issuer Purchases of Equity Securities

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

Performance Graph

The following graph presents a comparison of the yearly percentage change in the cumulative total return on our common stock over the period from January 1, 2008 to December 31, 2012, with the cumulative total return of the S&P 500 index and the Dow Jones U.S. Oil and Gas Exploration and Production Index over the same period. The graph assumes that $100 was invested on January 1, 2008 in our common stock at the closing market price at the beginning of this period and in each of the other two indices, and the reinvestment of all dividends, if any. This historic stock price performance is not necessarily indicative of future stock performance.



	Rex Energy	DJ U.S. E&P Index	S&P
December 31, 2007	$100	$100	$100
December 31, 2008	$ 25	$ 59	$ 62
December 31, 2009	$101	$ 83	$ 76
December 31, 2010	$114	$ 96	$ 86
December 31, 2011	$124	$ 91	$ 86
December 31, 2012	$109	$ 95	$ 97

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

ITEM 6. SELECTED FINANCIAL DATA

Summary Financial Data

The following table shows selected consolidated and combined financial data of Rex Energy Corporation. The historical consolidated financial data has been prepared for Rex Energy Corporation for the years ended December 31, 2012, 2011, 2010, 2009 and 2008. The historical consolidated financial statements for all years presented are derived from the historical audited financial data of Rex Energy Corporation. All material intercompany balances and transactions have been eliminated. This information should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," and our Consolidated Financial Statements and related notes as of December 31, 2012 and 2011 and for each of the years ended December 31, 2012, 2011 and 2010, included elsewhere in this report. These selected combined historical financial results may not be indicative of our future financial or operating results.

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

	Rex Energy Corporation Consolidated	Rex Energy Corporation Consolidated	Rex Energy Corporation Consolidated	Rex Energy Corporation Consolidated	Rex Energy Corporation Consolidated
	Year Ended December 31, ($ in Thousands, Except per Share Data)				
	2012	2011	2010	2009	2008
Statement of Operations Data:					
Operating Revenue:					
Oil, Natural Gas and NGL Sales	$134,574	$111,879	$ 67,224	$ 48,534	$ 84,013
Field Services Revenue	13,403	2,518	1,366	—	—
Other Revenue	162	209	173	157	123
Total Operating Revenue	148,139	114,606	68,763	48,691	84,136
Operating Expenses:					
Production and Lease Operating Expense	47,638	33,116	24,656	22,157	26,511
General and Administrative Expense	23,345	23,636	17,141	15,858	15,185
(Gain) Loss on Disposal of Assets	58	502	(16,395)	427	6,468
Impairment Expense	20,585	14,631	8,863	1,625	71,349
Exploration Expense	4,782	2,507	2,578	2,080	3,261
Depreciation, Depletion, Amortization & Accretion	45,437	27,856	21,568	25,205	37,904
Field Services Operating Expenses	8,240	1,750	1,188	—	—
Other Operating Expense	1,136	819	153	—	—
Total Operating Expenses	151,221	104,817	59,752	67,352	160,678
Income (Loss) from Operations	(3,082)	9,789	9,011	(18,661)	(76,542)
Other Income (Expense):					
Interest Expense	(6,443)	(2,514)	(1,240)	(826)	(763)
Gain (Loss) on Derivatives, Net	10,687	18,916	6,055	(7,913)	27,328
Other Income (Expense)	98,549	79	(321)	(161)	(114)
Gain (Loss) on Equity Method Investments	(3,921)	81	(200)	(9)	(54)
Total Other Income (Expense)	98,872	16,567	4,294	(8,909)	26,397
Income (Loss) from Continuing Operations Before Income Tax	95,790	26,351	13,305	(27,570)	(50,145)
Income Tax Benefit (Expense)	(38,549)	(8,270)	(5,500)	11,002	9,167
Income (Loss) from Continuing Operations	57,241	18,081	7,805	(16,568)	(40,978)
Income (Loss) from Discontinued Operations, Net of Income Taxes	(10,943)	(33,457)	(2,022)	323	(7,704)
Net Income (Loss)	46,298	(15,376)	5,783	(16,245)	(48,682)
Net Income (Loss) Attributable to Noncontrolling Interests	819	(7)	(253)	(12)	—
Net Income (Loss) Attributable to Rex Energy	$ 45,479	$ (15,369)	$ 6,036	$(16,233)	$ (48,682)
Earnings per Common Share					
Basic—income (loss) from continuing operations attributable to Rex common shareholders	$ 1.09	$ 0.41	$ 0.18	$ (0.45)	$ (1.18)
Basic—income (loss) from discontinued operations attributable to Rex common shareholders	(0.21)	(0.76)	(0.05)	0.01	(0.22)
Basic—net income (loss) attributable to Rex common shareholders	$ 0.88	$ (0.35)	$ 0.13	$ (0.44)	$ (1.40)
Basic—weighted average shares of common stock outstanding	51,543	43,930	43,281	36,806	34,595
Diluted—income (loss) from continuing operations attributable to Rex common shareholders	$ 1.08	$ 0.41	$ 0.18	$ (0.45)	$ (1.18)
Diluted—income (loss) from discontinued operations attributable to Rex common shareholders	(0.21)	(0.76)	(0.05)	0.01	(0.22)
Diluted—net income (loss) attributable to Rex common shareholders	$ 0.87	$ (0.35)	$ 0.13	$ (0.44)	$ (1.40)
Diluted—weighted average shares of common stock outstanding	52,025	44,476	43,670	36,806	34,595

	Year Ended December 31, ($ in thousands)				
	2012	2011	2010	2009	2008
Cash Flow Data:					
Cash provided by operating activities	$ 45,705	$ 64,507	$ 34,102	$ 20,774	$ 32,428
Cash used by investing activities	(100,742)	(276,574)	(94,921)	(30,061)	(127,800)
Cash provided by financing activities	87,216	212,855	66,245	7,823	101,333
Balance Sheet Data:					
Cash and Cash Equivalents	43,975	11,796	11,008	5,582	7,046
Property and Equipment (net of Accumulated Depreciation)	654,015	480,244	275,923	275,261	249,858
Total Assets	772,710	601,551	407,085	304,950	302,006
Current Liabilities, including current portion of long-term debt	55,535	63,366	63,337	32,411	17,353
Long-Term Debt, net of current maturities	249,249	225,138	10,120	23,049	15,000
Total Liabilities	360,416	309,277	102,409	84,753	70,158
Noncontrolling Interests	775	275	295	3,343	—
Stockholders' Equity	412,294	292,274	304,676	220,197	231,848
Other Financial Data:					
EBITDAX from Continuing Operations[1]	88,681	65,366	27,091	22,493	29,119

1 A non-GAAP financial measure. For a definition of EBITDAX and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please see "Non-GAAP Financial Measures."

Summary Operating and Reserve Data

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

	2012	2011	2010
Production			
Oil (Bbls)	732,066	694,452	691,574
Natural gas (Mcf)	18,016,700	8,912,250	3,088,598
NGLs (Bbls)	358,049	190,151	25,559
Mcf equivalent (Mcfe)	24,557,390	14,219,868	7,391,396
Oil and natural gas sales(a)			
Oil sales	$ 66,329	$ 63,515	$ 52,577
Natural gas sales	$ 52,992	$ 38,161	$ 13,789
NGLs sales	$ 15,253	$ 10,203	$ 858
Total	$ 134,574	$ 111,879	$ 67,224
Average sales price(a)			
Oil ($ per Bbl)	$ 90.61	$ 91.46	$ 76.03
Natural gas ($ per Mcf)	$ 2.94	$ 4.28	$ 4.46
NGLs ($ per Bbl)	$ 42.60	$ 53.66	$ 33.60
Mcf equivalent ($ per Mcfe)	$ 5.48	$ 7.87	$ 9.10
Average production cost			
Mcf equivalent ($ per Mcfe)	$ 1.94	$ 2.33	$ 3.34
Estimated proved reserves(b)			
Bcf equivalent (Bcfe)	618.1	366.2	201.7
% Oil and NGL	40%	25%	37%
% Proved producing	40%	45%	38%
PV-10 (millions)	$ 500.5	$ 539.6	$ 269.4
Standardized measure (millions)	$ 396.1	$ 413.9	$ 188.1

(a) Information excludes the impact of our financial derivative activities.

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

Non-GAAP Financial Measures

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

EBITDAX

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

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

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

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

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

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

The following table presents a reconciliation of our net income (loss) to our EBITDAX for each of the periods presented. For purposes of consistency with current calculations, we have revised certain amounts relating to prior period EBITDAX.

	Year Ended December 31, (in thousands)				
	2012	2011	2010	2009	2008
Net Income (Loss) From Continuing Operations	$ 57,241	$ 18,081	$ 7,805	$(16,568)	$(40,978)
Net (Income) Loss Attributable to Noncontrolling Interests	(819)	7	253	12	—
Income (Loss) From Continuing Operations Attributable to Rex Energy	56,422	18,088	8,058	(16,556)	(40,978)
Add Back Retroactive Portion of Pennsylvania Impact Fee	2,809	—	—	—	—
Add Back Depletion, Depreciation, Amortization and Accretion	45,437	27,856	21,568	25,205	37,904
Add Back Non-Cash Compensation Expense	3,140	1,601	907	1,557	2,990
Add Back Interest Expense[1]	6,443	2,514	1,951	1,595	1,014
Add Back Impairment Expense	20,585	14,631	8,863	1,625	71,349
Add Back Exploration Expense	4,782	2,507	2,578	2,080	3,261
Add (Less) Back (Gain) Loss on Disposal of Assets	(99,349)	502	(16,395)	427	6,468
Add Back (Less) Unrealized (Gain) Loss on Financial Derivatives	5,532	(12,704)	(5,960)	17,558	(43,746)
Less Non-Cash Portion of Noncontrolling Interests	(140)	(157)	(119)	(2)	—
Add Back Non-Cash Portion of Equity Method Investments	4,471	2,258	140	6	24
Add Back (Less) Income Tax Expense (Benefit)	38,549	8,270	5,500	(11,002)	(9,167)
EBITDAX from Continuing Operations	88,681	65,366	27,091	22,493	29,119
Net Income (Loss) From Discontinued Operations	$(10,943)	$(33,457)	$ (2,022)	$ 323	$ (7,704)
Add Back Depletion, Depreciation, Amortization and Accretion	—	85	1	—	1,565
Add Back Non-Cash Compensation Expense	(31)	24	7	—	—
Add Back Interest Expense	—	1	—	—	—
Add Back Impairment Expense	19,770	13,176	—	—	8,729
Add Back Exploration Expense	867	33,812	2,664	—	2,198
Add Back (Less) (Gain) Loss on Disposal of Assets	(2,126)	—	—	—	41
Add Back (Less) Unrealized (Gain) Loss on Financial Derivatives	—	—	—	(558)	558
Add Back (Less) Income Tax Expense (Benefit)	(8,489)	(15,302)	(1,440)	288	(1,736)
EBITDAX from Discontinued Operations	(952)	(1,661)	(790)	53	3,651
EBITDAX	$ 87,729	$ 63,705	$ 26,301	$ 22,546	$ 32,770

1 Includes realized settlements on interest rate swap.

PV-10

The following table shows the reconciliation of PV-10 to our standardized measure of discounted future net cash flows, the most directly comparable measure calculated and presented in accordance with GAAP. PV-10 represents our estimate of the present value, discounted at 10% per annum, of estimated future cash flows of our estimated proved reserves before income tax and asset retirement obligations. Our estimated future cash flows as of December 31, 2010, 2011 and 2012, were determined by using reserve quantities of estimated proved reserves and the periods in which they are expected to be developed and produced based on the prevailing economic conditions. The estimated future production for the years ended December 31, 2010, 2011 and 2012, was priced based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December, without escalation, using $76.03 per Bbl, $92.45 per Bbl and $90.92 per Bbl of oil, respectively, and $4.567 per MMBtu, $4.545 per MMBtu and $2.941 per MMBtu of natural gas, respectively, as adjusted by lease for transportation fees and regional price differentials. NGLs were priced at $31.71 per Bbl, $46.34 per Bbl and $32.91 per Bbl for the years ended December 31, 2010, 2011 and 2012, respectively, as adjusted by lease for transportation fees and regional price differentials. Management believes that PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our company. PV-10 should not be considered to be a superior measure to the standardized measure of discounted future net cash flows as computed under GAAP.

	2012	2011	2010
Reconciliation of standardized measure to PV-10			
PV-10	$500.5	$ 539.6	$269.4
Add: Present value of future income tax discounted at 10%	(79.6)	(107.0)	(64.1)
Add: Present value of future asset retirement obligations discounted at 10%	(24.8)	(18.7)	(17.2)
Standardized measure of discounted future net cash flows	$396.1	$ 413.9	$188.1

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

The following discussion and analysis should be read in conjunction with "Item 6. Selected Financial Data" and the Consolidated Financial Statements and related notes included elsewhere in this report. This discussion contains forward-looking statements reflecting our current expectations and estimates, and assumptions concerning events and financial trends that may affect our future operating results or financial position. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors, including those discussed in the sections entitled "Cautionary Note Regarding Forward-Looking Statements" and "Item 1A. Risk Factors" appearing elsewhere in this report. All financial and operating data presented are the results of continuing operations unless otherwise noted.

Overview of Our Business

We are an independent oil and gas company operating in the Appalachian Basin and Illinois Basin. In the Appalachian Basin, we are focused on our Marcellus Shale, Utica Shale and Upper Devonian Shale drilling and exploration activities. In the Illinois Basin, we are focused on the implementation of enhanced oil recovery on our properties as well as conventional oil production. We pursue a balanced growth strategy of exploiting our sizable inventory of high potential exploration drilling prospects while actively seeking to acquire complementary oil and natural gas properties. In addition to our drilling and exploration activities, we are also engaged in oil and gas field services, where we provide water sourcing, water disposal and water transfer capabilities for completion operations.

We are headquartered in State College, Pennsylvania, and have regional offices in Bridgeport, Illinois; Butler, Pennsylvania; Seven Fields, Pennsylvania; and Carrolton, Ohio.

We divide our operations into two principal business segments, exploration and production and field services.

Exploration and Production Segment

Our exploration and production segment engages in the exploration, acquisition, development and production of oil, natural gas and NGLs. We generally evaluate the performance of our exploration and production segment based on production volumes and net income (loss) from continuing operations, before income taxes. Our financial results from exploration and production depend upon many factors, particularly the price of oil, natural gas and NGLs. Commodity prices are affected by changes in market demand, which is impacted by overall economic activity, weather, refinery or pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future commodity prices, and therefore, we cannot determine what effect increases or decreases will have on our capital program, production volumes and future revenues. In addition to production volumes and commodity prices, finding and developing sufficient amounts of oil, natural gas and NGLs reserves at economical costs are critical to our long-term success.

Our revenues from exploration and production have increased annually from $67.4 million in 2010 to $112.1 million in 2011 and $134.7 million in 2012. Income from continuing operations for the years ended December 31, 2010, 2011 and 2012 totaled $14.0 million, $26.7 million and $92.2 million, respectively.

In 2012, we grew our production by 72.7% year-over-year to 67.1 Mmcfe/ day. The increase in production is primarily attributable to increased gas sales in Butler County due to the success of our drilling program and the commissioning of a second cryogenic gas processing plant, which is owned and operated by Markwest. We drilled 31.0 gross (21.0 net) wells within the Appalachian Basin, targeting primarily the Marcellus and Utica shales. In the Illinois Basin, we drilled eight gross (eight net) conventional wells. With a drilling success rate of 97.7% in 2012, we increased proved reserves by 68.8% from 366.2 Bcfe at December 31, 2011 to 618.1 Bcfe at

December 31, 2012. As of December 31, 2012, we had approximately 177,200 gross (103,100 net) acres in the Appalachian Basin, of which 22,800 gross (20,000 net) acres we believe are prospective for the liquids-rich portion of the Utica Shale.

In February 2012 we completed an underwritten public offering of 8,050,000 shares of our common stock, which included 1,050,000 shares of common stock issued upon the full exercise of the underwriters' over-allotment option, at a public offering price of $9.25 per share. The net proceeds of the transaction were approximately $70.6 million, after deducting underwriting discounts, commissions and other offering expenses. In May 2012, we divested our 28% interest in Keystone Midstream, a midstream joint venture in Butler County, Pennsylvania. Net proceeds were approximately $128.1 million after certain post-closing adjustments. As of December 31, 2012, approximately $7.2 million remained in an escrow account expected to be released in June 2013. In December 2012, we issued a $250.0 million aggregate principal amount of 8.875% senior notes in a private offering at an issue price of 99.3% due to mature on December 1, 2020. The net proceeds of the offering, after discounts and expenses, were approximately $242.2 million.

During 2011, we increased our proved reserves base by approximately 81.6%, from 201.7 Bcfe at December 31, 2010. The primary contributing factor to this increase was our continued drilling success in the Appalachian Basin, where we drilled 51.0 gross (25.9 net) wells which also resulted in an increase in production of approximately 92.4%. Notable among our drilling endeavors, we drilled two successful test wells, one in the Utica Shale and one in the Burkett Shale, solidifying our belief that there are multiple producing zones underlying a significant portion our acreage in Butler County, Pennsylvania.

In 2010, we entered into a joint venture agreement with Sumitomo. In accordance with the agreement, we sold a 15% non-operated interest to all depths in our Butler County, Pennsylvania project area, and Sumitomo also agreed to lease an additional 9,000 acres in this project area. The leasing arrangement was concluded during 2011; consequently, the final ownership percentages in the project area are approximately 70% to us and 30% to Sumitomo. In addition to our Butler County, Pennsylvania project area, we also sold a 20% non-operated interest in our joint venture area with WPX (discussed below) and a 50% non-operated interest in undeveloped acreage in Fayette and Centre counties, Pennsylvania. At closing, we received approximately $99.5 million in cash, which included a reimbursement for leasing expenses incurred subsequent to the effective date of September 1, 2010, in the amount of $7.6 million, and a reimbursement for drilling related expenses incurred subsequent to the effective date in the amount of approximately $7.5 million. As a part of the joint venture agreement, Sumitomo agreed to pay 80% of our net drilling and completion expenses up to approximately $58.8 million. For additional information on the transaction with Sumitomo, see Note 4, *Business and Oil and Gas Property Acquisitions and Dispositions*, to our Consolidated Financial Statements.

Field Services Segment

Our field services segment, which began operations in early 2010, operates and manages water sourcing, water transfer and water disposal services, primarily in the Appalachian Basin. Through this segment, we own and operate several water withdrawal points within the Commonwealth of Pennsylvania that we utilize to sell water to companies within the exploration and production industry for use in fracture stimulation activities. We also offer water transfer services via temporary or permanent pipelines and water processing services.

We generally evaluate the performance of our field services segment based on net income (loss) from continuing operations, before income taxes. Our financial results from field services are largely contingent on drilling and completion activities in the Appalachian Basin, particularly in regions where the Marcellus and Utica Shale plays are prominent. Our field services results are subject to similar economic risks as discussed for our exploration and production segment, such as commodity price risk, due to the relation to drilling and completion activity levels.

Our revenues from field services have increased annually from $1.4 million in 2010 to $2.5 million in 2011 and $13.4 million in 2012. Income (loss) from continuing operations for the years ended December 31, 2010, 2011 and 2012 totaled a loss of $0.7 million, a loss of $1.1 million and income of $2.0 million, respectively.

Source of Our Revenue

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

	Twelve Months Ended December 31,					
	2012	% of Total	2011	% of Total	2010	% of Total
Sources of Revenue ($ in thousands):						
Revenue from Oil Sales	$ 66,329	44.8%	$ 63,515	55.4%	$52,577	76.5%
Revenue from Natural Gas Sales	52,992	35.8%	38,161	33.3%	13,789	20.1%
Revenue from NGL Sales	15,253	10.3%	10,203	8.9%	858	1.2%
Field Services	13,403	9.0%	2,518	2.2%	1,366	2.0%
Other	162	0.1%	209	0.2%	173	0.2%
Total	$148,139	100.0%	$114,606	100.0%	$68,763	100.0%

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

Principal Components of Our Cost Structure

Our operating and other expenses consist of the following:

- *Production and Lease Operating Expenses.* Day-to-day costs incurred to bring hydrocarbons out of the ground and to the market together with the daily costs incurred to maintain our producing properties. Such costs also include workovers, repairs to our oil and gas properties not covered by insurance, and various production taxes that are paid based upon rates set by federal, state, and local taxing authorities.
- *General and Administrative Expenses.* Overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters and regional offices, costs of managing our production and development operations, audit and other professional fees, and legal compliance are included in general and administrative expense. General and administrative expense includes non-cash stock-based compensation expense as part of employee compensation.
- *Exploration Expenses.* Geological and geophysical costs, seismic costs, delay rentals and the costs of unsuccessful exploratory wells, also known as dry holes.
- *Field Service Operating Expenses.* Project related expenses incurred in correlation with our Field Services segment. These expenses are largely variable in nature and fluctuate commensurate with our level of activity, particularly on water transfer and water disposal projects. These charges include wages and benefits, insurance, field supplies, rental equipment and materials.

- *Interest.* We typically finance a portion of our working capital requirements and leasehold acquisitions with borrowings under our senior credit facility or senior notes. As a result, we incur substantial interest expense that is affected by both fluctuations in interest rates and our financing decisions. We may continue to incur significant interest expense as we continue to grow.
- *Depreciation, Depletion, Amortization and Accretion.* The systematic expensing of the capital costs incurred to acquire, explore and develop natural gas and oil. As a successful efforts company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and apportion these costs to each unit of production through depreciation, depletion and amortization expense. This also includes the systematic, monthly accretion of the future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities.
- *Income Taxes.* We are subject to state and federal income taxes. We do pay some state and federal income taxes where our IDC deductions do not exceed our taxable income or where state income taxes are determined on another basis. We have scheduled the timing of reversal of our deferred tax assets and believe we will use all of our net operating loss carryforwards prior to their expiration.

How We Evaluate Our Operations

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include EBITDAX (a non-GAAP measure), lease operating expense per Mcf equivalent ("Mcfe"), growth in our proved reserve base, and general and administrative expense per Mcfe. The following table presents these metrics for continuing operations for each of the three years ended December 31, 2012, 2011 and 2010.

	Performance Measurements		
	For the Years Ended December 31,		
	2012	2011	2010
EBITDAX ($ in thousands)	$88,681	$65,366	$27,091
Production Cost per Mcfe	$ 1.94	$ 2.33	$ 3.34
Total Estimated Proved Reserves (Bcfe)	618.1	366.2	201.7
G&A per Mcfe	$ 0.95	$ 1.66	$ 2.32

EBITDAX

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

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

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

Our EBTIDAX growth since 2010 has been commensurate with the growth of our Appalachian Basin operations, where we have been successful in our exploration and development of three producing horizons: the Marcellus, Utica and Upper Devonian (Burkett) Shales. The majority of our holdings in the Appalachian Basin have a liquids-producing component which, when combined with low operating costs, has enabled us to consistently improve our results. In addition, our Illinois Basin properties have continued to provide stable cash flows with 100.0% oil production.

Production Cost per Mcfe

Production costs are comprised of those expenses which are directly attributable to our producing oil and gas leases, including state and county production taxes, production related insurance, the cost of materials, maintenance, electricity, chemicals, gathering, processing, fuel and the wages of our field personnel. Our production costs per Mcfe are higher than those of many of our peers primarily because of the nature of our oil properties, many of which are mature waterflood properties. Our production cost per Mcfe produced in 2012 was $1.94 as compared to $2.33 in 2011 and $3.34 in 2010. As we continue to develop our non-proved properties, such as the Marcellus Shale, which have a lower operating cost, we believe this metric will continue to decrease on a per-unit basis.

Growth in our Proved Reserve Base

We measure our ability to grow our estimated proved reserves over the amount of our total annual production. As we produce oil and gas attributable to our estimated proved reserves, our estimated proved reserves decrease each year by that amount of production. We attempt to replace these produced estimated proved reserves each year through the addition of new estimated proved reserves through our drilling and other property improvement projects and through acquisitions. Our estimated proved reserves have increased since 2010, from 201.7 Bcfe at year end 2010 to 366.2 Bcfe at year end 2011 to 618.1 Bcfe at year end 2012. Our reserve replacement ratio for year end 2010 was approximately 1,559% based on total production for the year of 7.3 Bcfe and extensions, discoveries and other additions of 98.2 Bcfe. Our reserve replacement ratio for year end 2011 was approximately 1,096% based on total production for the year of 14.2 Bcfe, and extensions, discoveries and other additions of 178.7 Bcfe. Our reserve replacement ratio for year end 2012 was approximately 802% based on total production for the year of 24.6 Bcfe, and extensions, discoveries and other additions of 196.6 Bcfe.

Our estimated proved reserve base increased in 2012 when compared to 2011 predominately due to our successful drilling and exploration programs in the Marcellus Shale and, to a lesser extent, the Utica Shale. In addition to our successful drilling and exploration programs, we were able to add approximately 121.6 Bcfe of estimated proved reserves based on future estimated ethane recoveries which had not previously been recorded. During 2012, we executed an agreement to sell ethane as a separate product in our NGL stream, which is currently being utilized as plant fuel. As such, we booked for the first time in 2012 ethane barrels as part of our NGL reserves. For 2012, our proved reserve base in the Appalachian Basin increased by approximately 77.6%, while our estimated proved reserves in the Illinois Basin increased by 11.9%.

General and Administrative Expenses per Mcfe

Our general and administrative expenses include fees for well operating services, marketing, non-field level employee compensation and related benefits, office and lease expenses, insurance costs and professional fees, as well as other costs and expenses not directly related to field operations. Our management continually evaluates the level of our general and administrative expenses in relation to our production because these expenses have a direct impact on our profitability. In 2012 our general and administrative expenses per Mcfe produced decreased to $0.95 from $1.66 in 2011 and from $2.32 in 2010. As we continue to develop our non-proved properties, we believe this metric will continue to decrease on a per-unit basis.

Pennsylvania Impact Fee

During the first quarter of 2012, Pennsylvania state legislators instituted a natural gas impact fee on producers of unconventional natural gas. The fee will be imposed on every producer of unconventional natural gas and applies to unconventional wells spud in Pennsylvania regardless of when spudding occurred. Unconventional gas wells that were spud prior to 2012 are considered to be spud in 2011 for purposes of determining the fee, which is considered year one for those wells. The fee for each unconventional natural gas well is determined using the following matrix, with vertical unconventional natural gas wells being charged 20% of the applicable rates:

	<$2.25 (a)	$2.26 - $2.99 (a)	$3.00 - $4.99 (a)	$5.00 - $5.99 (a)	>$5.99 (a)
Year One	$40,000	$45,000	$50,000	$55,000	$60,000
Year Two	$30,000	$35,000	$40,000	$45,000	$55,000
Year Three	$25,000	$30,000	$30,000	$40,000	$50,000
Year 4—10	$10,000	$15,000	$20,000	$20,000	$20,000
Year 11—15	$ 5,000	$ 5,000	$10,000	$10,000	$10,000

(a) Pricing utilized for determining annual fees is based on the arithmetic mean of the NYMEX settled price for the near-month contract as reported by the Wall Street Journal for the last trading day of each month of a calendar year for the 12-month period ending December 31.

For the twelve months ended December 31, 2012, we incurred approximately $5.4 million in fees related to the natural gas impact fee. Of this amount, approximately $2.8 million was related to the first year fees for unconventional gas wells drilled prior to 2012. We have recorded these fees as Production and Lease Operating Expense on our Consolidated Statement of Operations.

Results of Continuing Operations

General Overview

Operating revenue increased 29.3% for 2012 over 2011. This increase was primarily due to increased oil and gas production in each of our operating regions, partially offset by lower commodity prices for oil, natural gas and NGLs. For 2012, total production increased 72.7% to 24,557 MMcfe from 14,220 MMcfe in 2011.

Operating expenses increased $46.9 million in 2012, or 44.5%, as compared to 2011. Operating expenses are primarily composed of production expenses, general and administrative expenses (“G&A”), gain (loss) on disposal of assets, exploration expenses, impairment of oil and gas properties, field services operating expenses and depreciation, depletion, amortization and accretion expenses (“DD&A”). Much of the increase in operating expenses is due to an increase in variable type expenses that fluctuate with our level of activity, such as lease operating expenses, DD&A and field services operating expenses. Also contributing to the increase were higher impairment charges, which were primarily incurred on non-core dry gas assets in the Appalachian Basin.

Comparison of the Year Ended December 31, 2012 to the Year Ended December 31, 2011

Oil and gas revenue for the years ended December 31, 2012 and 2011 is summarized in the following table:

	December 31,			
	2012	2011	Change	%
Oil and Gas Revenue ($ in thousands):				
Oil sales revenue	$ 66,329	$ 63,515	$ 2,814	4.4%
Oil derivatives realized	(286)	(670)	384	57.3%
Total oil revenue and derivatives realized	$ 66,043	$ 62,845	$ 3,198	5.1%
Gas sales revenue	$ 52,992	$ 38,161	$ 14,831	38.9%
Gas derivatives realized	16,095	6,882	9,213	133.9%
Total gas revenue and derivatives realized	$ 69,087	$ 45,043	$ 24,044	53.4%
NGL sales revenue	$ 15,253	$ 10,203	$ 5,050	49.5%
NGL derivatives realized	410	—	410	100.0%
Total NGL revenue	$ 15,663	$ 10,203	$ 5,460	53.5%
Consolidated sales	$ 134,574	$ 111,879	$ 22,695	20.3%
Consolidated derivatives realized	16,219	6,212	10,007	161.1%
Total oil and gas revenue and derivatives realized	$ 150,793	$ 118,091	$ 32,702	27.7%
Total Mcfe production	24,557,390	14,219,868	10,337,522	72.7%
Average realized price per Mcfe, including the effects of derivatives	$ 6.14	$ 8.30	$ (2.16)	(26.0%)

Average realized price received for oil and gas during 2012 was $6.14 per Mcfe, a decrease of 26.0%, or $2.16 per Mcfe, from the prior year. The average realized price for oil, including the effects of derivatives, in 2012 decreased 0.3% or $0.28 per barrel, whereas the average realized price for natural gas, including the effects of derivatives, decreased 24.1%, or $1.22 per Mcf, from 2011. The average realized price for NGLs, including the effects of derivatives, in 2012 decreased 18.5%, or $9.91 per barrel, from 2011. Our derivative activities effectively increased net realized prices by $0.66 per Mcfe in 2012 and $0.44 per Mcfe in 2011.

Production volume for 2012 increased 72.7% from 2011 primarily due to the success of our Marcellus and Utica Shale horizontal drilling activities in the Appalachian Basin, where production increased approximately 101.2%, or 10.2 Bcfe. In our Butler County, Pennsylvania operated area, during June 2012, our midstream providers put into service the new Bluestone cryogenic gas processing plant, which added to our existing production and processing capacity in the region. Production in the Illinois Basin for 2012 increased by 3.7% to 719,191 barrels as compared to the same period in 2011. The natural decline of our Illinois Basin properties was offset by increased oil production from our infill drilling and recompletion operations in the region.

Overall, our production for 2012 averaged approximately 67,097 Mcfe per day of which 17.9% was attributable to oil, 8.7% was attributable to natural gas liquids and 73.4% was attributable to natural gas.

Statements of Operations for the years ended December 31, 2012 and 2011 are as follows:

	December 31,			
	2012	2011	Change	%
OPERATING REVENUE				
Oil, Natural Gas and NGL Sales	$134,574	$111,879	$ 22,695	20.3%
Field Services Revenue	13,403	2,518	10,885	N/M
Other Revenue	162	209	(47)	(22.5%)
TOTAL OPERATING REVENUE	148,139	114,606	33,533	29.3%
OPERATING EXPENSES				
Production and Lease Operating Expense	47,638	33,116	14,522	43.9%
General and Administrative Expense	23,345	23,636	(291)	(1.2%)
Loss on Disposal of Assets	58	502	(444)	(88.4%)
Impairment Expense	20,585	14,631	5,954	40.7%
Exploration Expense	4,782	2,507	2,275	90.7%
Depreciation, Depletion, Amortization and Accretion	45,437	27,856	17,581	63.1%
Field Services Operating Expense	8,240	1,750	6,490	N/M
Other Operating Expense	1,136	819	317	38.7%
TOTAL OPERATING EXPENSES	151,221	104,817	46,404	44.3%
INCOME (LOSS) FROM OPERATIONS	(3,082)	9,789	(12,871)	(131.5%)
OTHER INCOME (EXPENSE)				
Interest Expense	(6,443)	(2,514)	(3,929)	156.3%
Gain on Derivatives, Net	10,687	18,916	(8,229)	(43.5%)
Other Income	98,549	79	98,470	N/M
Gain (Loss) on Equity Method Investments	(3,921)	81	(4,002)	N/M
TOTAL OTHER INCOME	98,872	16,562	82,310	N/M
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX	95,790	26,351	69,439	263.5%
Income Tax Expense	(38,549)	(8,270)	(30,279)	N/M
INCOME FROM CONTINUING OPERATIONS	57,241	18,081	39,160	216.6%
Loss From Discontinued Operations, Net of Income Taxes	(10,943)	(33,457)	22,514	(67.3%)
NET INCOME (LOSS)	46,298	(15,376)	61,674	N/M
Net Income (Loss) Attributable to Noncontrolling Interests	819	(7)	826	N/M
NET INCOME (LOSS) ATRRIBUTABLE TO REX ENERGY	$ 45,479	$ (15,369)	$ 60,848	N/M

Field Services Revenue for 2012 of approximately $13.4 million increased $10.9 million from 2011. We generate field services revenue from various field service activities such as the management of water sourcing, water transfer and water disposal activities in the Appalachian Basin. Increased activity and demand in the Appalachian Basin surrounding the Marcellus and Utica Shale plays has led to the growth of our field service activities particularly water transfer to service well completion activities.

Production and Lease Operating Expense increased approximately $14.5 million, or 43.9%, in 2012 from 2011. We experienced lifting cost increases that are commensurate with the increase in producing wells in the Appalachian Basin as they relate to variable type costs such as compression, processing and gathering. Additionally, the Commonwealth of Pennsylvania instituted the Pennsylvania Impact Fee during the first quarter of 2012, which accounted for approximately $5.4 million in expense for 2012, of which approximately $2.8 million related to the retroactive portion for wells drilled prior to 2012. On a per unit of production basis, our lifting costs decreased to $1.94 per Mcfe during 2012 from $2.33 in 2011.

General and Administrative Expense of approximately $23.3 million for 2012 decreased approximately $0.3 million, or 1.2%, from 2011. We recorded approximately $2.5 million related to the settlement of our lawsuit in the Appalachian Basin during the second quarter of 2011, which was partially offset by a number of factors including the growth of our Appalachian Basin operations and our corporate headquarters. On a per unit of production basis, our G&A expenses decreased to $0.95 per Mcfe during 2012 from $1.66 per Mcfe during 2011.

Impairment Expense increased to $20.6 million in 2012 from $14.6 million, or 40.7%, in 2011. We evaluate impairment of our properties when events occur that indicate that the carrying value of these properties may not be recoverable. During 2012, our impairment charges were primarily due to non-core dry gas properties in the Appalachian Basin for which depressed natural gas prices caused a shift in the economics of the wells and certain tracts of acreage, rendering the carrying value of the assets to be greater than the fair value. During 2011, we incurred approximately $11.6 million of impairment expense related to conventional shallow natural gas properties in the Appalachian Basin due to their estimated fair value being less than their carrying value as of December 31, 2011. These wells are characterized as older wells that produce at much lower rates than the unconventional shale plays. While they are less capital intensive and have lower operating costs, their lower production levels combined with lower commodity pricing make them susceptible to impairment write downs. The remainder of our impairment in 2011 was primarily due to the expiration of leased acreage.

Exploration Expense of oil and gas properties for 2012 increased approximately $2.3 million from $2.5 million in 2011. Approximately $4.4 million of the expense incurred during 2012 is attributable to geological and geophysical expenditures and delay rental payments predominately associated with properties in the Appalachian Basin. The remaining expense incurred during 2012 is related to the plugging of two exploratory Marcellus Shale wells that were spud during 2011 in Butler County, Pennsylvania. Minimal drilling was completed on these wells before a strategic decision was made to abandon the well locations and redeploy capital to other leases that will enable us to hold additional acreage by production. The expenses incurred in 2011 were due to geological and geophysical expenditures and delay rental payments primarily associated with leases in the Appalachian Basin.

Depletion, Depreciation, Amortization and Accretion Expense of approximately $45.4 million for 2012 increased approximately $17.6 million, or 63.1%, from 2011. The period over period increase in DD&A expense is consistent with the growth in our asset base, reserves and production since the comparable period in 2011.

Field Service Operating Expense for 2012 totaled approximately $8.2 million as compared to $1.8 million in 2011. Our field services operating expenses are largely variable in nature and fluctuate commensurate with our level of activity. Increased activity and demand in the Appalachian Basin surrounding the Marcellus and Utica Shale plays has led to the growth of our field service activities, particularly those associated with water transfer for well completion operations.

Interest Expense, net of Interest Income, for 2012 was approximately $6.4 million as compared to $2.5 million for 2011. The increase in interest expense, net of interest income, was primarily due to a higher average long-term debt balance, including our Second Lien Credit Agreement, which was outstanding until repayment in December 2012 and carried a higher interest rate than our senior credit facility. Both the senior credit facility and the Second Lien Credit Agreement are discussed later in the report, and in Note 11, *Long-Term Debt,* to our Consolidated Financial Statements.

Gain on Derivatives, net for 2012 was approximately $10.7 million as compared to $18.9 million for 2011. This change was attributable to the volatility of oil, NGL and gas commodity prices in the marketplace along with changes in our portfolio of outstanding collars and swap derivatives. Losses from derivative activities generally reflect higher oil and gas prices in the marketplace than were in effect at the time we entered into a derivative contract, while gains would suggest the opposite. Our derivative program is designed to provide us with greater predictability of future cash flows at expected levels of oil, NGL and gas production volumes given the highly volatile oil and gas commodities market.

Other Income for 2012 was approximately $98.5 million as compared to $0.1 million in 2011. The gain recognized during 2012 is attributable to the sale of our investment in Keystone Midstream, for which we recorded a gain of approximately $99.4 million, which included a post-closing adjustment of $0.5 million and the receipt of escrow amounts of approximately $7.2 million.

Income Tax Expense for 2012 was approximately $38.5 million as compared to $8.3 million in 2011. The change was primarily due to the tax effect of the gain on the sale of our investment in Keystone Midstream during 2012.

Net Income (Loss) Attributable to Rex Energy for 2012 was net income of approximately $45.5 million, as compared to a net loss of approximately $15.4 million for 2011 as a result of the factors discussed above.

Comparison of the Year Ended December 31, 2011 to the Year Ended December 31, 2010

Oil and gas revenue for the years ended December 31, 2011 and 2010 is summarized in the following table:

	December 31,			
	2011	2010	Change	%
Oil and Gas Revenue ($ in thousands):				
Oil sales revenue	$ 63,515	$ 52,577	$ 10,938	20.8%
Oil derivatives realized	(670)	(3,861)	3,191	82.6%
Total oil revenue and derivatives realized	$ 62,845	$ 48,716	$ 14,129	29.0%
Gas sales revenue	$ 38,161	$ 13,789	$ 24,372	176.7%
Gas derivatives realized	6,882	4,667	2,215	47.5%
Total gas revenue and derivatives realized	$ 45,043	$ 18,456	$ 26,587	144.1%
Total NGL revenue	$ 10,203	$ 858	$ 9,345	1,089.2%
Consolidated sales	$ 111,879	$ 67,224	$ 44,655	66.4%
Consolidated derivatives realized	6,212	806	5,406	670.7%
Total oil and gas revenue and derivatives realized	$ 118,091	$ 68,030	$ 50,061	73.6%
Total Mcfe production	14,219,868	7,391,396	6,828,472	92.4%
Average realized price per Mcfe, including the effects of derivatives	$ 8.30	$ 9.20	$ (0.90)	(9.8%)

Average realized price received for oil and gas during 2011 was $8.30 per Mcfe, a decrease of 9.8%, or $0.90 per Mcfe, from the prior year. The average realized price for oil, including the effects of derivatives, in 2011 increased 28.5% or $20.05 per barrel, whereas the average realized price for natural gas, including the effects of derivatives, decreased 15.4%, or $0.92 per Mcf, from 2010. Our derivative activities effectively increased net realized prices by $0.44 per Mcfe in 2011 and $0.11 per Mcfe in 2010.

Production volume for 2011 increased 92.4% from 2010 primarily due to the success of our Marcellus Shale horizontal drilling plan in the Appalachian Basin, where production increased approximately 210.2%, or 6.8 Bcfe. In the Illinois Basin, our oil production increased 0.3% as compared to 2011, where ASP production and lease optimization activity helped to offset the natural decline of the properties. Our production for 2011 averaged approximately 38,959 Mcfe per day of which 29.3% was attributable to the Illinois Basin and 70.7% to the Appalachian Basin.

Statements of Operations for the years ended December 31, 2011 and 2010 are as follows:

	December 31,			
	2011	2010	Change	%
OPERATING REVENUE				
Oil, Natural Gas and NGL Sales	$111,879	$ 67,224	$ 44,655	66.4%
Field Services Revenue	2,518	1,366	1,152	84.3%
Other Revenue	209	173	36	20.8%
TOTAL OPERATING REVENUE	114,606	68,763	45,843	66.7%
OPERATING EXPENSES				
Production and Lease Operating Expense	33,116	24,656	8,460	34.3%
General and Administrative Expense	23,636	17,141	6,495	37.9%
(Gain) Loss on Disposal of Assets	502	(16,395)	16,897	103.1%
Impairment Expense	14,631	8,863	5,768	65.1%
Exploration Expense	2,507	2,578	(71)	(2.8%)
Depreciation, Depletion, Amortization and Accretion	27,856	21,568	6,288	29.2%
Field Services Operating Expense	1,750	1,188	562	47.3%
Other Operating Expense	819	153	666	N/M
TOTAL OPERATING EXPENSES	104,817	59,752	45,065	75.4%
INCOME (LOSS) FROM OPERATIONS	9,789	9,011	778	8.6%
OTHER INCOME (EXPENSE)				
Interest Expense	(2,514)	(1,240)	(1,274)	102.7%
Gain (Loss) on Derivatives, Net	18,916	6,055	12,861	212.4%
Other Income (Expense)	79	(321)	400	124.6%
Gain (Loss) on Equity Method Investments	81	(200)	281	140.5%
TOTAL OTHER INCOME (EXPENSE)	16,562	4,294	12,268	285.7%
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAX	26,351	13,305	13,046	98.1%
Income Tax Benefit (Expense)	(8,270)	(5,500)	(2,770)	50.4%
INCOME (LOSS) FROM CONTINUING OPERATIONS	18,081	7,805	10,276	131.7%
Income (Loss) From Discontinued Operations, Net of Income Taxes	(33,457)	(2,022)	(31,435)	1,554.6%
NET INCOME (LOSS)	(15,376)	5,783	(21,159)	(365.9%)
Net Loss Attributable to Noncontrolling Interests	(7)	(253)	(246)	(97.2%)
NET INCOME (LOSS) ATRRIBUTABLE TO REX ENERGY	$(15,369)	$ 6,036	$(21,405)	(354.6%)

Field Services Revenue for 2011 of approximately $2.5 million increased $1.2 million, or 84.3%, from 2010. We generate field services revenue from various field service activities such as management of water sourcing, water transfer and water disposal activities in the Appalachian Basin. Increased activity and demand in the Appalachian Basin surrounding the Marcellus and Utica Shale plays has led to the growth of our field service activities, and particularly water transfer to service well completion activities.

Production and Lease Operating Expense increased approximately $8.5 million, or 34.3%, in 2011 from 2010. The increase is primarily due to processing and gathering fees incurred in our Butler County, Pennsylvania operating region. We produce wet gas in this region, which requires processing before it can be sold. As such, we jointly constructed a cryogenic gas processing plant for which we pay fees to have our gas transported and processed before sale. We incurred approximately $4.6 million in expenses related to processing and gathering during 2011 and approximately $0.3 million in 2010. Also contributing to our increased expenses was the growth of our Appalachian Basin operations, where we placed into service 51.0 gross (25.9 net) wells in 2011.

General and Administrative Expense for 2011 of approximately $23.6 million increased approximately $6.5 million, or 37.9%, from 2010. The increase in general and administrative costs is attributable to legal expenses, severance wages and an overall increase in headcount. We incurred $2.5 million in legal costs associated with the settlement of our leasing lawsuit in Westmoreland County, Pennsylvania. During 2011, we entered into separation agreements with several employees for which we incurred approximately $1.0 million in severance costs. The remainder of the increase during 2011 is primarily attributable to our continued efforts to hire and retain high quality personnel. We have incurred higher recruiting, wages and benefits costs to achieve this goal, which includes approximately $1.6 million in non-cash compensation in 2011 as compared to $0.9 million in 2010.

(Gain) Loss on Disposal of Assets for 2011 was a loss of approximately $0.5 million as compared to a gain of $16.4 million for 2010. From time to time, we sell or otherwise dispose of certain fixed assets and wells that are no longer effectively used by us, and a gain or loss may be recognized when such an asset is sold.

Impairment Expense increased to $14.6 million in 2011 from $8.9 million, or 64.0%, in 2010. We evaluate impairment of our properties when events occur that indicate that the carrying value of these properties may not be recoverable. During 2011 we incurred approximately $11.6 million of impairment expense related to conventional shallow natural gas properties in the Appalachian Basin due to their estimated fair value being less than their carrying value as of December 31, 2011. These wells are characterized as older wells that produce at much lower rates than the unconventional shale plays. While they are less capital intensive and have lower operating costs, their lower production levels combined with lower commodity pricing make them susceptible to impairment write downs. The remainder of our impairment in 2011 was primarily due to the expiration of leased acreage. During 2010, impairment expense was primarily related to two test wells in Clearfield County, Pennsylvania. We determined that the carrying value of these two test wells, which were in various stages of drilling and completion, was not recoverable due to a lack of a sales outlet and no then-current plans by us to complete the wells for commercial production. We periodically evaluate the capitalized costs associated with properties that are outside of our current scope of operations as to their recoverability based on changes brought about by economic factors and potential shifts in our business strategy. As economic and strategic conditions change and we continue to develop unproved properties, our estimates of impairment will likely change and we may increase or decrease expense.

Exploration Expense of oil and gas properties for 2011 decreased approximately $0.1 million from $2.6 million in 2010. Exploration costs incurred by us during 2011 and 2010 were primarily due to delay rental payments on undeveloped acreage and seismic and micro-seismic activities on our properties.

Depletion, Depreciation, Amortization and Accretion Expense of approximately $27.9 million for 2011 increased approximately $6.3 million, or 29.2%, from 2010. Depletion expenses incurred during 2010 were lower than what would normally be expected primarily due to the carry obligations by our joint venture partners, whereby our partners would fund the majority of the cost to drill and complete wells to earn their share of the working interest. We expect future depletion to trend more in line with production as the carry obligations have been expended, pending any future carry obligations.

Field Services Operating Expense for 2011 totaled approximately $1.8 million as compared to $1.2 million in 2010. These costs are comprised of operating expenses incurred in connection with our field services joint venture. Our field services operating expenses are largely variable in nature and fluctuate commensurate with our level of activity. Increased activity and demand in the Appalachian Basin surrounding the Marcellus and Utica Shale plays has led to the growth of our field service activities, particularly those associated with water transfer for well completion operations. We did not have any field service operations prior to 2010.

Interest Expense, net of Interest Income, for 2011 was approximately $2.5 million as compared to $1.2 million for 2010. The increase in interest expense, net of interest income, was primarily due to a higher average outstanding balance on our senior credit facility.

Gain on Derivatives, net for 2011 was a gain of approximately $18.9 million as compared to $6.1 million for 2010. This change was attributable to the volatility of oil and gas commodity prices in the marketplace along with changes in our portfolio of outstanding collars and swap derivatives. Losses from derivative activities generally reflect higher oil and gas prices in the marketplace than were in effect at the time we entered into a derivative contract, while gains would suggest the opposite. Our derivative program is designed to provide us with greater predictability of future cash flows at expected levels of oil and gas production volumes given the highly volatile oil and gas commodities market.

Net Income (Loss) Attributable to Rex Energy for 2011 was a loss of approximately $15.4 million, as compared to net income of approximately $6.0 million for 2010 as a result of the factors discussed above.

Capital Resources and Liquidity

Our primary financial resource is our base of oil, natural gas and NGL reserves. During 2012, $230.3 million of capital, which excludes our joint venture investments, was expended on drilling projects, facilities and related equipment and acquisitions of acreage. The capital program was funded by net cash flow from operations and through borrowings on our senior credit facility, the sale of our investment in Keystone Midstream and the net proceeds from (i) our public offering of common stock and (ii) our private offering of $250.0 million in 8.875% senior notes. We expect that our 2013 capital budget of $250.0 million will continue to be funded primarily by cash flow from operations, non-core asset sales and borrowings under our senior credit facility. We currently believe that we have sufficient liquidity and cash flow to meet our obligations for the next twelve months; however, a significant drop in commodity prices, particularly natural gas, or a reduction in production or reserves could adversely affect our ability to fund capital expenditures and meet our financial obligations. Also, our obligations may change due to acquisitions, divestitures and continued growth. We may also elect to issue additional shares of stock, subordinated notes or other securities to fund capital expenditures, acquisitions, extend maturities or to repay debt.

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

Our cash flow from operations is driven by commodity prices and production volumes. Prices for oil and gas are driven by, among other things, seasonal influences of weather, national and international economic and political environments and, increasingly, from heightened demand for hydrocarbons from emerging nations. Our working capital is significantly influenced by changes in commodity prices, and significant declines in prices could decrease our exploration and development expenditures. Cash flows from operations and borrowings from our senior credit facility have been primarily used to fund exploration and development of our oil and gas interests. As of December 31, 2012, we had no borrowings under our senior credit facility and had the full borrowing base of $240.0 million available to us with approximately $44.0 million of cash on hand. As of December 31, 2012, we were in compliance with all required debt covenants.

Future Liquidity Considerations

In connection with certain marketing, transportation and processing agreements that we have entered into, we may be obligated to pay fees in connection with these agreements of $76.1 million over the next five years, depending on our levels of production. Also in connection with certain of these agreements, we have guaranteed the payment of obligations up to a maximum of $406.4 million over the life of the agreements.

Financial Condition and Cash Flows for the Years Ended December 31, 2012, 2011 and 2010

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

	For the Years Ended December 31, ($ in Thousands)		
	2012	2011	2010
Cash flows provided by operating activities	$ 45,705	$ 64,507	$ 34,102
Cash flows used in investing activities	(100,742)	(276,574)	(94,921)
Cash flows provided by financing activities	87,216	212,855	66,245
Net increase in cash and cash equivalents	$ 32,179	$ 788	$ 5,426

Net cash provided by operating activities decreased by approximately $18.8 million in 2012 when compared to 2011, to $45.7 million. This decrease in our cash flows provided by operating activities was primarily impacted by our increased operating expenses, specifically our lifting costs and expenses related to our field services segment. Also contributing to the decrease was a change in our working capital balance and lower commodity prices. Partially offsetting these increases were higher production and sales volumes. Net cash provided by operating activities increased by approximately $30.4 million in 2011 when compared to 2010, to $64.5 million. This increase is primarily due to increased oil and natural gas production, in addition to higher crude oil prices as compared to 2010. Partially offsetting these increases were higher production costs and G&A expenses.

Net cash used in investing activities decreased by approximately $175.8 million in 2012 when compared to 2011, to $100.7 million. This decrease was in large part due to the sale of our ownership in Keystone Midstream, for which we have received net proceeds of approximately $128.1 million. Other factors contributing to the decrease include a decrease in acquisitions of acreage and a decrease in investments to our equity method investments. Net cash used in investing activities increased by approximately $181.7 million in 2011 when compared to 2010, to $276.6 million. Approximately $118.8 million of this increase is due to our growth and expansion during the year as we drilled, completed and placed into service wells in our Appalachian Basin region. Also contributing to the increase in net investing were lower proceeds on sale of assets of $76.5 million during 2011, which was primarily due to the Sumitomo joint venture that occurred in 2010.

Net cash provided by financing activities decreased by approximately $125.6 million in 2012 when compared to 2011, to $87.2 million. During 2012, we received combined proceeds from draws on our senior credit facility, our public offering of common stock and our private offering of senior notes of approximately $439.2 million, which was partially offset by repayments of outstanding debt of approximately $351.0 million. This compares to 2011 when we had net proceeds on long-term debt after repayments of approximately $215.0 million. Net cash provided by financing activities increased by approximately $146.6 million in 2011 when compared to 2010, to $212.9 million. During 2011, we increased our borrowings under our credit agreements by $155.0 million and reduced repayments of debt by $73.0 million.

Effects of Inflation and Changes in Price

Our results of operations and cash flows are affected by changing oil and natural gas prices. If the price of oil and natural gas increases or decreases, there could be a corresponding increase or decrease in our operating costs, as well as an increase or decrease in revenues. Inflation has had a minimal effect on us.

Critical Accounting Policies and Recent Accounting Pronouncements

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

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

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

Accounts Receivable

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

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

Revenue Recognition

As it pertains to our exploration and production business segment, oil, NGL and natural gas revenue is recognized when the oil or natural gas is delivered to or collected by the respective purchaser, a sales agreement exists, collection for amounts billed is reasonably assured and the sales price is fixed or determinable. Title to the produced quantities transfers to the purchaser at the time the purchaser collects or receives the quantities. In the case of oil and NGL sales, title is transferred to the purchaser when the oil or NGLs leaves our stock tanks and enters the purchaser's trucks. In the case of natural gas production, title is transferred when the gas passes through the meter of the purchaser. It is the measurement of the purchaser that determines the amount of oil or natural gas purchased. Prices for such production are defined in sales contracts and are readily determinable based on certain publicly available indices. The purchasers of such production have historically made payment for oil and natural gas purchases within 30-60 days of the end of each production month. We periodically review the difference between the dates of production and the dates we collect payment for such production to ensure that receivables from those purchasers are collectible. The point of sale for our oil, NGL and natural gas production is at its applicable field gathering system. We do not recognize revenue for oil and NGL production held in stock tanks before delivery to the purchaser.

To the extent actual quantities and values of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and price for those products are estimated and recorded as Accounts Receivable in the Consolidated Balance Sheets and Oil, Natural Gas and NGL Sales on the Statements of Operations.

For our field services segment, our services are generally sold based upon purchase orders, contracts or other agreements with customers that include fixed or determinable prices. We recognize revenue when services are performed and collection of the relevant receivables is probable. We contract for services either on a day rate or other contracted rate. In certain situations, revenue is generated from transactions that may include multiple products and services under one contract or agreement and which may be delivered to the customer over an extended period of time. Revenue from these arrangements is recognized in accordance with the above criteria and as each item or service is delivered.

Natural Gas and Oil Reserve Quantities

Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. For the years ended December 31, 2012 and 2011, Netherland Sewell and Associates, Inc. ("NSAI") prepared a consolidated reserve and economic evaluation of our proved oil and gas reserves. These engineers were selected for their geographic expertise and their historical experience in engineering certain properties. The technical persons responsible for preparing the estimates of our proved reserves meet the requirements with regards 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. Our independent third-party engineers do not own an interest in any of our properties and are not employed by us on a contingent basis. The preparation of our proved reserve estimates are completed in accordance with our internal control procedures, which include the verification of input data used by NSAI, as well as intense management review and approval.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Estimates of our crude oil and natural gas reserves, and the projected cash flows derived from these reserve estimates, are prepared by our engineers in accordance with guidelines established by the SEC. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. The certainty of our reserve estimates is a function of many factors, including the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates. Any of the assumptions inherent in these factors could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of natural gas and oil eventually recovered. The independent reserve engineer estimates reserves annually on December 31. This annual estimate results in a new DD&A rate, which we use for the preceding fourth quarter after adjusting for fourth quarter production.

Derivative Instruments

We use put and call options (collars), fixed rate swap contracts, swaptions, puts and three-way collars to manage price risks in connection with the sale of oil, natural gas and NGLs. We have also, in the past, used interest rate swap agreements to manage interest rate risks associated with our variable rate credit facility. We have established the fair value of all derivative instruments using estimates determined by our counterparties and other third party providers. These values are based upon, among other things, future prices, volatility, time to maturity and credit risk. The values we report in our consolidated financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

We report our derivative instruments at fair value and include them in the Consolidated Balance Sheets as assets or liabilities. The accounting for changes in fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. We do not designate our derivatives as hedging instruments, therefore, any changes in fair value are recognized immediately in earnings.

Oil and Natural Gas Property, Depreciation and Depletion

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

Depletion is calculated using the unit-of-production method. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. We periodically review estimated proved reserve estimates and make changes as needed to depletion expenses to account for new wells drilled, acquisitions, divestitures and other events which may have caused significant changes in our estimated proved reserves. The costs of unproved properties are withheld from the depletion base until such time as they are proved. When estimated proved reserves are assigned, the cost of the property is added to costs subject to depletion calculations. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Undeveloped leasehold cost is allocated to the associated producing properties as the undeveloped acreage is developed. Individually significant non-producing properties are periodically assessed for impairment of value. Service properties, equipment and other assets are depreciated using the straight-line method over their estimated useful lives of three to 40 years.

When circumstances indicate that an asset may be impaired, we compare expected undiscounted future cash flows at a producing field to the unamortized capitalized cost of the asset. If the future undiscounted cash flows, based on our estimate of future natural gas and oil prices, operating costs, anticipated production from estimated proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate. For unproved oil and gas properties, we analyze activity on the acreage prior to evaluating any fair value indicators, such as current drilling activity, drilling success and future development plans. When evaluating the value our unproved oil and gas properties, we utilize active market prices for similar acreage to use as a comparison tool against the carrying value of our properties. If the active market prices for similar acreage do not support our carrying values we then utilize estimates of future value that will be created from the future development of these properties. If future estimated fair value of these properties is lower than the capitalized cost, the capitalized cost is reduced to the estimated future fair value. We recognized approximately $20.6 million, $14.6 million and $8.9 million of impairment from continuing operations on certain oil and gas properties for the years ending December 31, 2012, 2011 and 2010, respectively. We recorded these charges as Impairment Expense on our Consolidated Statements of Operations. For additional information, see Note 18, *Impairment Expense*, to our Consolidated Financial Statements.

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

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

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

Deferred Financing Costs and Other Assets—Net

At December 31, 2012, we had deferred financing costs and other assets consisting of $10.0 million, which was primarily made up of loan costs that are amortized using the effective interest method and the straight line method over their respective estimated lives, which is, on average, three to eight years. We amortize any costs incurred to renew or extend the terms of existing debt over the contract term or estimated useful life, as applicable. Our senior notes are amortized utilizing the effective interest method. For the years ended December 31, 2012, 2011, and 2010, we recorded amortization expense on all deferred financing costs from continuing operations of $1.2 million, $0.8 million and $0.5 million, respectively.

Future Abandonment Cost

Future abandonment costs are recognized as obligations associated with the retirement of tangible long-lived assets that result from the acquisition and development of the asset. We recognize the fair value of a liability for a retirement obligation in the period in which the liability is incurred. For natural gas and oil properties, this is the period in which the natural gas or oil well is acquired or drilled. The future abandonment cost is capitalized as part of the carrying amount of our natural gas and oil properties at its fair value. The liability is then accreted each period until the liability is settled or the natural gas or oil well is sold, at which time the liability is reversed. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement cost.

Deferred Income Taxes

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

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

Contingent Liabilities

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

Stock-based Compensation

We recognize in the Consolidated Financial Statements the cost of employee services and non-employee director services received in exchange for awards of equity instruments based on the grant date fair value of those awards. We use a standard option pricing model (i.e. Black-Scholes) to measure the fair value of employee stock options and stock appreciation rights and a Monte Carlo simulation technique to value restricted stock awards that are tied to market performance. The fair value of non-market based restricted stock awards is determined based on the fair market value of our common stock on the date of the grant.

The benefits associated with the tax deductions in excess of recognized compensation cost are reported as a financing cash flow when realized. We recognize compensation costs related to awards with graded vesting on a straight-line basis over the requisite service period for each separately vesting portion of the award as if the award were, in-substance, multiple awards (for additional information, see Note 17, *Employee Benefit and Equity Plans,* to our Consolidated Financial Statements). Stock appreciation rights are classified as a liability and are re-measured at fair value each reporting period.

Capitalization of Interest

We capitalize interest on capital projects, most notably during the drilling and completion of oil and natural gas wells. For the years ended December 31, 2012, 2011 and 2010, we capitalized interest costs of $3.0 million, $1.2 million and $0, respectively.

Earnings per Share

Earnings per common share are computed by dividing consolidated net income attributable to us by the weighted average number of common shares outstanding. Diluted earnings per common share are computed by dividing consolidated net income attributable to us by the weighted average number of common shares outstanding during the period, including any potentially dilutive outstanding securities, such as options and warrants. The potentially dilutive outstanding securities are calculated using the treasury stock method. At December 31, 2012, we had 53,213,264 common shares outstanding, 502,253 options outstanding and 20,500 stock appreciation rights outstanding with no outstanding warrants or other potentially dilutive securities. For additional information, see Note 14, *Earnings per Common Share*, to our Consolidated Financial Statements.

Recent Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update ("ASU") 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities.* ASU 2011-11 provides new disclosure requirements related to offsetting arrangements to allow investors to better compare financial statements prepared in accordance with IFRS and U.S. GAAP. The amendment requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. An entity is required to apply the amendments for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods, including retrospective application for all comparative periods presented. Although we currently are not engaged in any arrangements that would be effected by these disclosure requirements, we believe that ASU 2011-11 may have a material impact on future disclosures pending our entrance into an offsetting arrangement.

In May 2011, the FASB issued ASU 2011-04, *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS.* ASU 2011-04 generally provides a uniform framework for fair value measurements and related disclosures between GAAP and International Financial Reporting Standards ("IFRS"). Additional disclosure requirements in the update include: (1) for Level 3 fair value measurements, quantitative information about unobservable inputs used, a description of the valuation process used by the entity, and a qualitative discussion about the sensitivity of the measurements to changes in the unobservable inputs; (2) for an entity's use of a nonfinancial asset that is different from the asset's highest and best use, the reason for the difference; (3) for financial instruments not measured at fair value but for which disclosure of fair value is required, the fair value hierarchy level in which the fair value measurements were determined; and (4) the disclosures of all transfers between Level 1 and Level 2 of the fair value hierarchy. This update is effective for annual and interim periods beginning on or after December 31, 2011. We adopted ASU 2011-04 on January 1, 2012, with no material impact.

In December 2010, the FASB issued ASU 2010-29, *Disclosure of Supplementary Pro Forma Information for Business Combinations* ("ASU 2010-29"). The amendments to the codification clarify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. Additionally, the supplemental pro forma disclosures under Topic 805 have been expanded to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The amendments in ASU 2010-29 are effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. Although we have not entered into any significant business combinations in our recent history, we believe that ASU 2010-29 may have a material impact on future disclosures depending on the size and nature of any future business combinations that we may enter into. We adopted ASU 2010-29 on January 1, 2011.

Volatility of Oil and Natural Gas Prices

Our revenues, future rate of growth, results of operations, financial condition and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent upon prevailing prices of oil and natural gas.

We account for our natural gas and oil exploration and production activities under the successful efforts method of accounting (for additional information, see Note 2, *Summary of Significant Accounting Policies,* of our Consolidated Financial Statements).

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

For the twelve-month period ended December 31, 2012, the net realized gain on oil, natural gas and NGL derivatives was approximately $16.2 million. For the twelve-month period ended December 31, 2011, the net realized gain on oil and natural gas derivatives was approximately $6.2 million.

For the twelve month period ended December 31, 2012, the net unrealized loss on oil, natural gas and NGL derivatives was approximately $5.5 million, as compared to a net unrealized gain of approximately $12.7 million on oil and natural gas derivatives for 2011. The net realized and unrealized gains and losses are reported as Gain on Derivatives, net in the Consolidated Statements of Operations.

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

For a summary of our current oil and natural gas derivative positions at December 31, 2012, refer to Note 12, *Fair Value of Financial Instruments and Derivative Instruments*, of our Consolidated Financial Statements.

Contractual Obligations

In addition to our capital expenditure program, we are committed to making cash payments in the future on various types of contracts and obligations. As of December 31, 2012, we do not have any off-balance sheet debt or other such unrecorded obligations and we have not guaranteed the debt of any other party. The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2012. In addition to the contractual obligations listed in the table below, our balance sheet at December 31, 2012 reflects accrued interest on our senior credit facility of $1.2 million which was paid in January 2013.

The following summarizes our contractual financial obligations for continuing operations at December 31, 2012 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities.

	Payment due by period (in thousands)						
	2013	2014	2015	2016	2017	Thereafter	Total
8.875% Senior Notes(a)	$ —	$ —	$ —	$ —	$ —	$250,000	$250,000
Operating Leases	551	463	420	420	420	—	2,274
Other Loans and Notes Payable	1,686	378	336	277	—	—	2,677
Derivative Obligations(b)	1,389	1,510	—	—	—	—	2,899
Firm Commitments(c)	11,985	12,436	16,069	15,991	19,623	51,503	127,607
Asset Retirement Obligations(d)	609	935	846	467	504	21,461	24,822
Total Contractual Obligations	$16,220	$15,722	$17,671	$17,155	$20,547	$322,964	$410,279

(a) The amount included in the table represents the outstanding principal amount only. Interest paid on our senior notes will be approximately $21.5 million in 2013 and $22.2 million each year thereafter through 2020.
(b) Derivative obligations represent net open derivative contracts valued as of December 31, 2012.
(c) Includes sales, gathering and processing agreements.
(d) The ultimate settlement and timing cannot be precisely determined in advance.

Interest Rates

At December 31, 2012, we had zero borrowings outstanding under our senior credit facility. The interest rates on outstanding balances during 2012 on our senior credit facility and the second lien credit agreement averaged 2.5% and 7.3%, respectively. In conjunction with our private offering of senior notes in December 2012, we repaid in full, and terminated, our second lien credit agreement. Our $250.0 million senior notes bear interest at 8.875% annually and will be paid bi-annually.

Off-Balance Sheet Arrangements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various risks, including energy commodity price risk. We expect energy prices to remain volatile and unpredictable. If energy prices were to decrease for a substantial period of time or decline significantly, revenues and cash flows would significantly decline, and our ability to borrow to finance our operations could be adversely impacted. Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of, and demand for, oil, natural gas and NGLs. Conversely, increases in the market prices for oil, natural gas and NGLs can have a favorable impact on our financial condition, results of operations and capital resources. Based on December 31, 2012 reserve estimates, we project that a 10% decline in the price per barrel of oil, price per barrel of NGLs and the price per Mcf of gas from average 2012 prices would reduce our gross revenues, before the effects of derivatives, for the year ending December 31, 2013 by approximately $15.5 million.

We have designed our hedging policy to reduce the risk of price volatility for our production in the natural gas, NGL and crude oil markets. Our risk management policy provides for the use of derivative instruments to manage these risks. The types of derivative instruments that we use include swaps, collars, put spreads, put options, swaptions and three-way collars. The volume of derivative instruments that we may use are governed by the risk management policy and can vary from year to year, but under most circumstances will apply to only a portion of our current and anticipated production, and will provide only partial price protection against declines in commodity prices. We are exposed to market risk on our open contracts, to the extent of changes in market prices of oil, natural gas and NGLs. However, the market risk exposure on these hedged contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity that is hedged. Further, if our counterparties should default, this protection might be limited as we might not receive the benefits of the hedges.

At December 31, 2012, the following commodity derivative contracts were outstanding:

Period	Volume	Put Option	Floor	Ceiling	Swap	Fair Market Value ($ in Thousands)
Oil						
2013—Collar	540,000 Bbl	$ —	$72.44	$112.56	$ —	$ (217)
2013—Swap	120,000 Bbl	—	—	—	91.41	(217)
2013—Three Way Collar	60,000 Bbl	65.00	80.00	100.00	—	(45)
2014—Three Way Collar	360,000 Bbl	65.00	82.33	104.27	—	(509)
	1,080,000 Bbl					$ (988)
Natural Gas						
2013—Swap	6,570,000 Mcf	$ —	$ —	$ —	$ 3.84	$ 1,631
2013—Three Way Collar	2,520,000 Mcf	3.35	4.17	4.88	—	986
2013—Collar	3,360,000 Mcf	—	4.77	5.68	—	4,211
2013—Put	2,640,000 Mcf	—	5.00	—	—	3,378
2013—Swaption	1,200,000 Mcf	—	—	—	4.50	354
2014—Call	1,800,000 Mcf	—	—	5.00	—	(366)
2014—Three Way Collar	4,800,000 Mcf	2.91	3.91	4.68	—	430
2014—Swap	2,400,000 Mcf	—	—	—	3.84	(195)
2014—Collar	1,800,000 Mcf	—	3.51	4.43	—	(166)
	27,090,000 Mcf					$10,263
Natural Gas Liquids						
2013—Swap	108,000 Bbl	$ —	$ —	$ —	$43.26	$ 535
	108,000 Bbl					$ 535

(1) Item 305(a) of Regulation S-K requires that tabular information relating to contract terms allow readers of the table to determine expected cash flows from the market risk sensitive instruments for each of the next five years. At December 31, 2012, we had commodity derivative contracts in place for the next two years, relating to production through 2014.

We are also exposed to market risk related to adverse changes in interest rates. Our interest rate risk exposure results primarily from fluctuations in short-term rates, which are LIBOR and prime rate based, as determined by our lenders, and may result in reductions of earnings or cash flows due to increases in the interest rates we pay on our obligations. We have used, in the past, an interest rate swap agreement to manage risk associated with interest payments on amounts outstanding from variable rate borrowings under our senior credit facility. Under our interest rate swap agreement, we agreed to pay an amount equal to a specified rate of interest times a notional principal amount, and to receive in return, a specified variable rate of interest times the same notional principal amount. This swap expired in November 2010.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REX ENERGY CORPORATION

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors
Rex Energy Corporation:

We have audited the accompanying consolidated balance sheets of Rex Energy Corporation and subsidiaries (the Company) as of December 31, 2012 and 2011 and the related consolidated statements of operations, changes in noncontrolling interests and stockholders' equity (deficit), and cash flows for the years 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 audits. The accompanying consolidated financial statements of the Company as of December 31, 2010, were audited by other auditors whose reports thereon dated March 3, 2011, expressed an unqualified opinion on those statements, before the effects of the adjustments to retrospectively adjust for disclosures for a change in the composition of reportable segments discussed in Note 3 to the consolidated financial statements.

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, 2012 and 2011, and the results of their operations and their cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

We also have audited adjustments to the 2010 consolidated financial statements to retrospectively adjust the disclosures for a change in the composition of reportable segments discussed in Note 3 to the consolidated financial statements. In our opinion, such adjustments are appropriate and have been properly applied. We were not engaged to audit, review, or apply any procedures to the 2010 consolidated financial statements of the Company other than with respect to the adjustments and, accordingly, we do not express an opinion or any other form of assurance on the 2010 consolidated financial statements taken as a whole.

We have also audited, in accordance with standards of the Public Company Accounting Oversight Board (United States), the Company's internal controls over financial reporting as of December 31, 2012, based on criteria established in *Internal Controls—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 14, 2013 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP
Dallas, Texas
March 14, 2013

Report of Independent Registered Public Accounting Firm

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

We have audited, before the effects of the retrospective adjustments to the disclosures for a change in the composition of reportable segments discussed in Note 3 to the consolidated financial statements, the accompanying consolidated statements of operations, owners' equity and noncontrolling interests, and cash flows of Rex Energy Corporation for the year ended December 31, 2010. Rex Energy Corporation's management is responsible for these financial statements. Our responsibility is to express an opinion on these financial statements based on our 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 the financial statements are free of material misstatement. Our audit included 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, and 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, before the effects of the retrospective adjustments to the disclosures for a change in the composition of reportable segments discussed in Note 3 to the consolidated financial statements, present fairly, in all material respects, the consolidated results of operations and cash flows of Rex Energy Corporation for the year ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

We were not engaged to audit, review, or apply any procedures to the retrospective adjustments to the disclosures for a change in the composition of reportable segments discussed in Note 3 to the consolidated financial statements and, accordingly, we do not express an opinion or any other form of assurance about whether such retrospective adjustments are appropriate and have been properly applied. Those retrospective adjustments were audited by other auditors.

Malin, Bergquist & Company, LLP
Pittsburgh, Pennsylvania
March 3, 2011

REX ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS
($ in Thousands, Except Share and Per Share Data)

	December 31, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 43,975	$ 11,796
Accounts Receivable	24,980	17,717
Taxes Receivable	6,429	0
Short-Term Derivative Instruments	12,005	10,404
Assets Held For Sale	2,279	24,808
Inventory, Prepaid Expenses and Other	1,316	1,191
Total Current Assets	90,984	65,916
Property and Equipment (Successful Efforts Method)		
Evaluated Oil and Gas Properties	485,448	349,938
Unevaluated Oil and Gas Properties	161,618	123,241
Other Property and Equipment	50,073	43,542
Wells and Facilities in Progress	96,798	66,548
Pipelines	6,116	4,408
Total Property and Equipment	800,053	587,677
Less: Accumulated Depreciation, Depletion and Amortization	(146,038)	(107,433)
Net Property and Equipment	654,015	480,244
Deferred Financing Costs and Other Assets—Net	10,029	3,405
Equity Method Investments	16,978	41,683
Long-Term Deferred Tax Asset	0	1,727
Long-Term Derivative Instruments	704	8,576
Total Assets	$ 772,710	$ 601,551
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$ 31,134	$ 41,558
Accrued Expenses	22,421	15,682
Short-Term Derivative Instruments	1,389	2,363
Current Deferred Tax Liability	539	2,141
Liabilities Related to Assets Held for Sale	52	1,622
Total Current Liabilities	55,535	63,366
8.875% Senior Notes Due 2020	250,000	0
Discount on Senior Notes	(1,742)	0
Senior Secured Line of Credit and Long-Term Debt	991	225,138
Long-Term Derivative Instruments	1,510	1,275
Long-Term Deferred Tax Liability	23,625	84
Other Deposits and Liabilities	5,675	744
Future Abandonment Cost	24,822	18,670
Total Liabilities	360,416	309,277
Commitments and Contingencies (See Note 9)		
Stockholders' Equity		
Common Stock, $.001 par value per share, 100,000,000 shares authorized and 53,213,264 shares issued and outstanding on December 31, 2012 and 44,859,220 shares issued and outstanding on December 31, 2011	52	44
Additional Paid-In Capital	451,062	376,843
Accumulated Deficit	(39,595)	(84,888)
Rex Energy Stockholders' Equity	411,519	291,999
Noncontrolling Interests	775	275
Total Stockholders' Equity	412,294	292,274
Total Liabilities and Stockholders' Equity	$ 772,710	$ 601,551

See accompanying notes to the consolidated financial statements

REX ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS
($ and Shares in Thousands, Except Share and Per Share Data)

	Year Ended December 31,		
	2012	2011	2010
OPERATING REVENUE			
Oil, Natural Gas and NGL Sales	$134,574	$111,879	$ 67,224
Field Services Revenue	13,403	2,518	1,366
Other Revenue	162	209	173
TOTAL OPERATING REVENUE	148,139	114,606	68,763
OPERATING EXPENSES			
Production and Lease Operating Expense	47,638	33,116	24,656
General and Administrative Expense	23,345	23,636	17,141
(Gain) Loss on Disposal of Asset	58	502	(16,395)
Impairment Expense	20,585	14,631	8,863
Exploration Expense	4,782	2,507	2,578
Depreciation, Depletion, Amortization and Accretion	45,437	27,856	21,568
Field Services Operating Expense	8,240	1,750	1,188
Other Operating Expense	1,136	819	153
TOTAL OPERATING EXPENSES	151,221	104,817	59,752
INCOME (LOSS) FROM OPERATIONS	(3,082)	9,789	9,011
OTHER INCOME (EXPENSE)			
Interest Expense	(6,443)	(2,514)	(1,240)
Gain on Derivatives, Net	10,687	18,916	6,055
Other Income (Expense)	98,549	79	(321)
Income (Loss) from Equity Method Investments	(3,921)	81	(200)
TOTAL OTHER INCOME	98,872	16,562	4,294
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX	95,790	26,351	13,305
Income Tax Expense	(38,549)	(8,270)	(5,500)
INCOME FROM CONTINUING OPERATIONS	57,241	18,081	7,805
Loss From Discontinued Operations, Net of Income Taxes	(10,943)	(33,457)	(2,022)
NET INCOME (LOSS)	46,298	(15,376)	5,783
Net Income (Loss) Attributable to Noncontrolling Interests	819	(7)	(253)
NET INCOME (LOSS) ATTRIBUTABLE TO REX ENERGY	$ 45,479	$ (15,369)	$ 6,036
Earnings Per Common Share:			
Basic—income from continuing operations attributable to Rex common shareholders	$ 1.09	$ 0.41	$ 0.18
Basic—loss from discontinued operations attributable to Rex common shareholders	(0.21)	(0.76)	(0.05)
Basic—net income (loss) attributable to Rex common shareholders	$ 0.88	$ (0.35)	$ 0.13
Basic—weighted average shares of common stock outstanding	51,543	43,930	43,281
Diluted—income from continuing operations attributable to Rex common shareholders	$ 1.08	$ 0.41	$ 0.18
Diluted—loss from discontinued operations attributable to Rex common shareholders	(0.21)	(0.76)	(0.05)
Diluted—net income (loss) attributable to Rex common shareholders	$ 0.87	$ (0.35)	$ 0.13
Diluted—weighted average shares of common stock outstanding	52,025	44,476	43,670

See accompanying notes to the consolidated financial statements

REX ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CHANGES IN NONCONTROLLING INTERESTS AND STOCKHOLDERS' EQUITY (DEFICIT)
(in Thousands)

	Common Stock		Additional Paid-In Capital	Accumulated Deficit	Rex Energy Stockholders' Equity	Noncontrolling Interests	Total Stockholders' Equity
	Shares	Par					
Balance December 31, 2009	36,818	$37	$292,372	$(75,555)	$216,854	$ 3,343	$220,197
Non-cash compensation expense	0	0	965	0	965	0	965
Issuance of common stock, net of issuance costs	6,900	7	80,192	0	80,199	0	80,199
Capital contributions	0	0	0	0	0	287	287
Restricted stock, net	567	0	0	0	0	0	0
Stock option exercises	22	0	327	0	327	0	327
Deconsolidation of Keystone Midstream Services, LLC	0	0	0	0	0	(3,082)	(3,082)
Net Income (Loss)	0	0	0	6,036	6,036	(253)	5,783
Balance December 31, 2010	44,307	44	373,856	(69,519)	304,381	295	304,676
Non-cash compensation	0	0	1,625	0	1,625	0	1,625
Capital distributions	0	0	0	0	0	(13)	(13)
Restricted stock, net	413	0	0	0	0	0	0
Stock option exercises	139	0	1,362	0	1,362	0	1,362
Net Loss	0	0	0	(15,369)	(15,369)	(7)	(15,376)
Balance December 31, 2011	44,859	44	376,843	(84,888)	291,999	275	292,274
Non-cash compensation	0	0	3,079	(186)	2,893	0	2,893
Issuance of common stock, net of issuance costs	8,050	8	70,575	0	70,583	0	70,583
Restricted stock, net	252	0	0	0	0	0	0
Stock option exercises	52	0	565	0	565	0	565
Capital distributions	0	0	0	0	0	(319)	(319)
Net Income	0	0	0	45,479	45,479	819	46,298
Balance December 31, 2012	53,213	$52	$451,062	$(39,595)	$411,519	$ 775	$412,294

See accompanying notes to the consolidated financial statements

REX ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
($ in Thousands)

	For the Years Ended December 31,		
	2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income (Loss)	$ 46,298	$ (15,376)	$ 5,783
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities			
(Gain) Loss from Equity Method Investments	3,921	(81)	200
Non-cash Expenses	3,191	1,745	1,251
Depreciation, Depletion, Amortization and Accretion	46,441	28,446	21,806
Deferred Income Tax Expense (Benefit)	23,665	(7,339)	3,771
Unrealized (Gain) Loss on Derivatives	5,532	(12,704)	(5,960)
Dry Hole Expense	656	32,769	3
(Gain) Loss on Sale of Assets and Equity Method Investments	(100,551)	502	(16,395)
Impairment Expense	40,355	27,808	8,863
Changes in operating assets and liabilities			
Accounts Receivable	(13,698)	11,118	(14,527)
Inventory, Prepaid Expenses and Other Assets	(92)	86	(216)
Accounts Payable and Accrued Expenses	(6,770)	(1,128)	32,323
Other Assets and Liabilities	(3,243)	(1,339)	(2,800)
NET CASH PROVIDED BY OPERATING ACTIVITIES	45,705	64,507	34,102
CASH FLOWS FROM INVESTING ACTIVITIES			
Proceeds from Joint Venture Leasing Initiatives	260	3,209	6,352
Change in Restricted Cash	0	16,086	(16,086)
Contributions to Equity Method Investments	(4,087)	(23,204)	(14,018)
Proceeds from the Sale of Assets and Equity Method Investments	133,425	2,729	79,229
Acquisitions of Undeveloped Acreage	(51,802)	(78,569)	(72,385)
Capital Expenditures for Development of Oil & Gas Properties and Equipment	(178,538)	(196,825)	(78,013)
NET CASH USED IN INVESTING ACTIVITIES	(100,742)	(276,574)	(94,921)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from Long-Term Debt and Lines of Credit	126,730	240,000	85,000
Repayments of Long-Term Debt and Lines of Credit	(351,000)	(25,000)	(98,000)
Repayments of Loans and Other Notes Payable	(962)	(879)	(753)
Proceeds from 8.875% Senior Notes, net of Discount	248,250	0	0
Debt Issuance Costs	(6,397)	(2,615)	(701)
Settlement of Tax Withholdings Related to Share-Based Compensation Awards	(234)	0	0
Proceeds from the Issuance of Common Stock, Net of Issuance Costs	70,583	0	80,192
Proceeds from the Exercise of Stock Options	565	1,362	220
Capital Distributions by the Partners of Consolidated Joint Ventures	(319)	(20)	0
Capital Contributions by the Partners of Equity Method Investments and Consolidated Joint Ventures	0	7	287
NET CASH PROVIDED BY FINANCING ACTIVITIES	87,216	212,855	66,245
NET INCREASE IN CASH	32,179	788	5,426
CASH—BEGINNING	11,796	11,008	5,582
CASH—ENDING	$ 43,975	$ 11,796	$ 11,008
SUPPLEMENTAL DISCLOSURES			
Interest Paid	7,568	1,549	846
Taxes Paid	12,824	312	299
NON-CASH ACTIVITIES			
Equipment Financing	2,368	474	1,336

See accompanying notes to the consolidated financial statements

REX ENERGY CORPORATION
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION AND PRINCIPLES OF CONSOLIDATION

We are an independent oil and gas company operating in the Appalachian Basin and Illinois Basin. In the Appalachian Basin, we are focused on our Marcellus Shale, Utica Shale and Upper Devonian Shale drilling and exploration activities. In the Illinois Basin, we are focused on the implementation of enhanced oil recovery on our properties as well as conventional oil production. We pursue a balanced growth strategy of exploiting our sizable inventory of high potential exploration drilling prospects while actively seeking to acquire complementary oil and natural gas properties. In addition to our drilling and exploration activities, we are also engaged in oil and gas field services, where we provide water sourcing, water disposal and water transfer capabilities for completion operations.

The accompanying Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and include the accounts of all of our wholly owned subsidiaries. All material intercompany balances and transactions have been eliminated. Unless otherwise indicated, all references to "Rex Energy Corporation," "our," "we," "us" and similar terms refer to Rex Energy Corporation and its subsidiaries together. In preparing the accompanying financial statements, management has made certain estimates and assumptions that affect reported amounts in the financial statements and disclosures of contingencies.

Certain prior year amounts have been reclassified to conform to the report classifications for the year ended December 31, 2012, with no effect on previously reported net income, net income per share, accumulated deficit or stockholders' equity. All prior year amounts that have been reclassified are immaterial.

We consolidate all of our subsidiaries in the accompanying Consolidated Balance Sheets as of December 31, 2012 and 2011 and the Consolidated Statements of Operations, Cash Flows and Changes in Noncontrolling Interests and Stockholders' Equity (Deficit) for the years ended December 31, 2012, 2011 and 2010. Investments in unconsolidated affiliates in which we are able to exercise significant influence are accounted for using the equity method. All intercompany transactions and accounts have been eliminated.

Discontinued Operations

During December 2011, our board of directors approved a formal plan to sell our DJ Basin assets located in the states of Wyoming and Colorado. Pursuant to the rules for discontinued operations, these assets have been classified as Assets Held for Sale on our Consolidated Balance Sheets and the results of operations are reflected as Discontinued Operations in our Consolidated Statements of Operations. Unless otherwise noted, all disclosures and tables reflect the results of continuing operations and exclude any assets, liabilities or results from our discontinued operations. For additional information see Note 5, *Discontinued Operations/Assets Held for Sale*, to our Consolidated Financial Statements.

Subsidiary Guarantors

We filed a registration statement on Form S-3, which became effective June 15, 2011, with respect to certain securities described therein, including debt securities, which may be guaranteed by certain of our subsidiaries. Rex Energy Corporation is a holding company with no independent assets or operations. We contemplate that if guaranteed debt securities are offered pursuant to the registration statement, all guarantees will be full and unconditional and joint and several and any subsidiaries other than the subsidiary guarantors will be minor. In addition, there are no significant restrictions on the ability of Rex Energy Corporation to receive funds from our subsidiaries through dividends, loans, advances or otherwise.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the periods reported. Actual results could differ from these estimates.

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

Cash and Cash Equivalents

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

Accounts Receivable

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

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

At December 31, 2012, we carried approximately $18.1 million in production receivable, of which approximately $16.3 million were production receivables due from four purchasers. At December 31, 2011, we carried approximately $13.6 million in production receivables of which approximately $12.9 million were production receivables due from three purchasers. In addition, we carried approximately $2.1 million in receivables from Sumitomo Corporation at December 31, 2012 and $3.0 million at December 31, 2011 (see Note 4, *Business and Oil and Gas Property Acquisition Dispositions*, to our Consolidated Financial Statements) that was in relation to our joint operations.

Inventory

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

Oil and Natural Gas Property, Depreciation and Depletion

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

Depletion is calculated using the unit-of-production method. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. We periodically review estimated proved reserve estimates and make changes as needed to depletion expenses to account for new wells drilled, acquisitions, divestitures and other events which may have caused significant changes in our estimated proved reserves. The costs of unproved properties are withheld from the depletion base until such time as they are proved. When estimated proved reserves are assigned, the cost of the property is added to costs subject to depletion calculations. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Undeveloped leasehold cost is allocated to the associated producing properties as the undeveloped acreage is developed. Individually significant non-producing properties are periodically assessed for impairment of value. Service properties, equipment and other assets are depreciated using the straight-line method over their estimated useful lives of three to 40 years.

When circumstances indicate that an asset may be impaired, we compare expected undiscounted future cash flows at a producing field to the unamortized capitalized cost of the asset. If the future undiscounted cash flows, based on our estimate of future natural gas and oil prices, operating costs, anticipated production from estimated proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate. For unproved oil and gas properties, we analyze activity on the acreage prior to evaluating any fair value indicators, such as current drilling activity, drilling success and future development plans. When evaluating the value of our unproved oil and gas properties, we utilize active market prices for similar acreage to use as a comparison tool against the carrying value of our properties. If the active market prices for similar acreage do not support our carrying values we then utilize estimates of future value that will be created from the future development of these properties. If future estimated fair value of these properties is lower than the capitalized cost, the capitalized cost is reduced to the estimated future fair value. We recognized approximately $20.6 million, $14.6 million and $8.9 million of impairment from continuing operations on certain oil and gas properties for the years ending December 31, 2012, 2011 and 2010, respectively. We recorded these charges as Impairment Expense on our Consolidated Statements of Operations. For additional information, see Note 18, *Impairment Expense*, to our Consolidated Financial Statements.

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

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

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

Natural Gas and Oil Reserve Quantities

Our estimate of proved reserves is based on the quantities of oil, natural gas and NGLs that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. For the years ended December 31, 2012 and 2011, Netherland Sewell and Associates, Inc. ("NSAI") prepared a consolidated reserve and economic evaluation of our proved oil and gas reserves. The preparation of our proved reserve estimates are completed in accordance with our internal control procedures, which include the verification of input data used by NSAI, as well as management review and approval.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Estimates of our crude oil, natural gas and NGL reserves, and the projected cash flows derived from these reserve estimates, are prepared by our engineers in accordance with guidelines established by the SEC. The independent reserve engineer estimates reserves annually on December 31. This annual estimate results in a new depletion rate, which we use for the preceding fourth quarter after adjusting for fourth quarter production.

Deferred Financing Costs and Other Assets—Net

At December 31, 2012, we had deferred financing costs and other assets consisting of $10.0 million, which is primarily made up of loan costs that are amortized using the effective interest method and the straight line method over their respective estimated lives, which is, on average, three to eight years. We amortize any costs incurred to renew or extend the terms of existing debt over the contract term or estimated useful life, as applicable. For the years ended December 31, 2012, 2011 and 2010, we recorded amortization expense from continuing operations of $1.2 million, $0.8 million and $0.5 million, respectively.

The following is a summary of our deferred financing costs and other assets at the dates indicated:

	December 31, 2012 (in thousands)	**December 31, 2011 (in thousands)**
Deferred Financing Costs and Other Assets—Gross	$ 9,524	$ 5,637
Accumulated Amortization	(1,922)	(2,329)
Deferred Financing Costs and Other Assets—Net[1]	$ 7,602	$ 3,308

[1] Does not include approximately $2.4 million associated with advanced royalty payments for the year ended December 31, 2012, for which we expect to recover through future production and royalties.

Specific to our loan costs, we have incurred gross debt issuance costs of approximately $6.1 million, $2.6 million and $0.7 million for the years ended December 31, 2012, 2011 and 2010, respectively, which are presented net of accumulated amortization of $1.9 million, $1.1 million and $0.6 million, respectively, and include deferred financing from our senior notes.

Future Abandonment Cost

Future abandonment costs are recognized as obligations associated with the retirement of tangible long-lived assets that result from the acquisition and development of the asset. We recognize the fair value of a liability for a retirement obligation in the period in which the liability is incurred. For natural gas and oil properties, this is the period in which the natural gas or oil well is acquired or drilled. The future abandonment cost is capitalized as part of the carrying amount of our natural gas and oil properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the natural gas or oil well is sold, at which time the liability is reversed. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement cost.

Accretion expense from continuing operations during the years ended December 31, 2012, 2011 and 2010 totaled approximately $2.1 million, $1.5 million and $1.7 million, respectively. These amounts are recorded as DD&A on our Consolidated Statements of Operations. During 2012, we recognized an increase of $4.0 million in the estimated present value of our asset retirement obligations, representing an increase in the estimate to plug and abandon our oil and natural gas wells. The revised estimates were primarily the result of increased abandonment estimates, which were driven by the trends of actual outcomes. We account for asset retirement obligations that relate to wells that are drilled jointly based on our interest in those wells.

	December 31, 2012 ($ in Thousands)	**December 31, 2011 ($ in Thousands)**
Beginning Balance	$18,670	$17,222
Asset Retirement Obligation Incurred	598	235
Asset Retirement Obligation Settled	(428)	(266)
Asset Retirement Obligation Cancelled or Sold Well Properties	0	0
Asset Retirement Obligation Revision of Estimated Obligation	3,953	0
Asset Retirement Obligation Accretion Expense	2,029	1,479
Total Asset Retirement Obligation	$24,822	$18,670

Revenue Recognition

As it pertains to our exploration and production business segment, oil, NGL and natural gas revenue is recognized when the oil or natural gas is delivered to or collected by the respective purchaser, a sales agreement exists, collection for amounts billed is reasonably assured and the sales price is fixed or determinable. Title to the produced quantities transfers to the purchaser at the time the purchaser collects or receives the quantities. In the case of oil and NGL sales, title is transferred to the purchaser when the oil or NGLs leaves our stock tanks and enters the purchaser's trucks. In the case of gas production, title is transferred when the gas passes through the meter of the purchaser. It is the measurement of the purchaser that determines the amount of oil or gas purchased. Prices for such production are defined in sales contracts and are readily determinable based on certain publicly available indices. The purchasers of such production have historically made payment for oil and natural gas purchases within 30-60 days of the end of each production month. We periodically review the difference between the dates of production and the dates we collect payment for such production to ensure that receivables from those purchasers are collectible. The point of sale for our oil, NGL and natural gas production is at its applicable field gathering system. We do not recognize revenue for oil and NGL production held in stock tanks before delivery to the purchaser.

To the extent actual quantities and values of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and price for those properties are estimated and recorded as Accounts Receivable in the Consolidated Balance Sheets and Oil, Natural Gas and NGL Sales on the Statements of Operations.

For our field services segment, our services are generally sold based upon purchase orders, contracts or other agreements with customers that include fixed or determinable prices. We recognize revenue when services are performed and collection of the relevant receivables is probable. We contract for services either on a day rate or other contracted rate. In certain situations, revenue is generated from transactions that may include multiple products and services under one contract or agreement and which may be delivered to the customer over an extended period of time. Revenue from these arrangements is recognized in accordance with the above criteria and as each item or service is delivered.

Derivative Instruments

We use put and call options (collars), fixed rate swap contracts, swaptions, puts and three-way collars to manage price risks in connection with the sale of oil, natural gas and NGLs. We have also, in the past, used interest rate swap agreements to manage interest rate risks associated with our variable rate credit facility. We have established the fair value of all derivative instruments using estimates determined by our counterparties and other third-parties. These values are based upon, among other things, future prices, volatility, time to maturity and credit risk. The values we report in our Consolidated Financial Statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

We report our derivative instruments at fair value and include them in the Consolidated Balance Sheets as assets or liabilities. The accounting for changes in fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated for hedge accounting, for financial accounting purposes, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any changes in fair value resulting from ineffectiveness are recognized immediately in earnings. During 2012, 2011 and 2010 we did not have any derivative instruments designated for hedge accounting.

For derivative instruments designated as fair value hedges, changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings. Derivative effectiveness is measured annually based on the relative changes in fair value between the derivative contract and the hedged item over time. For derivatives on oil, natural gas and NGL production activity, our evaluations are not documented, and as a result, we record changes on the derivative valuations through earnings. For additional information on our derivative instruments, see Note 12, *Fair Value of Financial Instruments and Derivative Instruments*, to our Consolidated Financial Statements.

Income Taxes

We are subject to income and other taxes in all areas in which we operate. When recording income tax expense, certain estimates are required because income tax returns are generally filed several months after the close of a calendar year, tax returns are subject to audit which can take years to complete, and future events often impact the timing of when income tax expenses and benefits are recognized. We have deferred tax assets relating to tax operating loss carryforwards and other deductible differences and deferred tax liabilities that relate to other temporary differences.

Deferred tax assets and liabilities are computed based on the difference between the financial statement and income tax bases of assets and liabilities using the enacted tax rate. Net deferred tax assets are required to be reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the net deferred tax asset will not be realized.

This process requires our management to make assessments regarding the timing and probability of the ultimate tax impact. We record valuation allowances on deferred tax assets if we determine it is more likely than not that the asset will not be realized. Actual income taxes could vary from these estimates due to future changes in income tax law, significant changes in the jurisdictions in which we operate, our inability to generate sufficient future taxable income, or unpredicted results from the final determination of each year's liability by taxing authorities. These changes could have a significant impact on our financial position.

The accounting estimate related to the tax valuation allowance requires us to make assumptions regarding the timing of future events, including the probability of expected future taxable income and available tax planning opportunities. These assumptions require significant judgment because actual performance has fluctuated in the past and may do so in the future. The impact that changes in actual performance versus these estimates could have on the realization of tax benefits as reported in our results of operations could be material. We continuously evaluate facts and circumstances representing positive and negative evidence in the determination of our ability to realize the deferred tax assets.

We recognize a tax position if it is more likely than not that it will be sustained upon examination. If we determine it is more likely than not a tax position will be sustained based on its technical merits, we record the impact of the position in our Consolidated Financial Statements at the largest amount that is greater than fifty percent likely of being realized upon ultimate settlement. These estimates are updated at each reporting date based on the facts, circumstances and information available. We are also required to assess at each reporting date whether it is reasonably possible that any significant increases or decreases to the unrecognized tax benefits will occur during the next twelve months (for additional information, see Note 13, *Income Taxes,* to our Consolidated Financial Statements). Our policy is to recognize interest and penalties on any unrecognized tax benefits in interest expense and general and administrative expense, respectively.

Stock-based Compensation

We recognize in the Consolidated Financial Statements the cost of employee and non-employee director services received in exchange for awards of equity instruments based on the grant date fair value of those awards. We use a standard option pricing model (i.e. Black-Scholes) to measure the fair value of employee stock options and stock appreciation rights and a Monte Carlo simulation technique to value restricted stock awards that are tied to market performance. The fair value of non-market based restricted stock awards is determined based on the fair market value of our common stock on the date of the grant.

The benefits associated with the tax deductions in excess of recognized compensation cost are reported as a financing cash flow when realized. We recognize compensation costs related to awards with graded vesting on a straight-line basis over the requisite service period for each separately vesting portion of the award as if the award were, in-substance, multiple awards (for additional information, see Note 17, *Employee Benefit and Equity Plans,* to our Consolidated Financial Statements). Stock appreciation rights are classified as a liability and are re-measured at fair value each reporting period.

Capitalization of Interest

We capitalize interest on capital projects, most notably during the drilling and completion of oil and natural gas wells. For the years ended December 31, 2012, 2011 and 2010, we capitalized interest costs of $3.0 million, $1.2 million and $0, respectively.

Earnings per Share

Earnings per common share are computed by dividing consolidated net income attributable to us by the weighted average number of common shares outstanding. Diluted earnings per common share are computed by dividing consolidated net income attributable to us by the weighted average number of common shares outstanding during the period, including any potentially dilutive outstanding securities, such as options and warrants. The potentially dilutive outstanding securities are calculated using the treasury stock method. At December 31, 2012, we had 53,213,264 common shares outstanding, 502,253 options outstanding and 20,500 stock appreciation rights outstanding with no outstanding warrants or other potentially dilutive securities. For additional information, see Note 14, *Earnings per Common Share*, to our Consolidated Financial Statements.

Capital Leases

As a lessee, we determine if a lease is a capital lease if it meets one of four of the following criteria:

- The ownership of the leased property transfers to us by the end of the lease term, or shortly thereafter, in exchange for the payment of a nominal fee.
- The lease contains a bargain purchase option.
- The lease term is equal to 75% or more of the estimated economic life of the leased property.
- The present value at the beginning of the lease term of the minimum lease payments, excluding that portion of the payments representing executor costs such as insurance, maintenance, and taxes to be paid by the lessor, including any profit thereon, equals or exceeds 90% of the excess of the fair value of the leased property to the lessor at the lease inception over any related investment tax credit retained by the lessor and expected to be realized by the lessor.

As of December 31, 2012 we had capital leases on field vehicles being used in our Illinois and Appalachian Basin operations as well as in our field services operating segment. We recorded these leases as Other Property and Equipment on our Consolidated Balance Sheets in the amount of $1.6 million as of December 31, 2012, and $2.3 million as of December 31, 2011. The remaining obligation to be paid on these leases totaled approximately $1.5 million, of which $1.0 million was classified as Senior Secured Line of Credit and Long-Term Debt under Long-Term Liabilities and $0.5 million was classified as Accounts Payable under Current Liabilities on our Consolidated Balance Sheets, all of which is expected to be paid by 2016.

Recent Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update ("ASU") 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities*. ASU 2011-11 provides new disclosure requirements related to offsetting arrangements to allow investors to better compare financial statements prepared in accordance with IFRS and U.S. GAAP. The amendment requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. An entity is required to apply the amendments for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods, including retrospective application for all comparative periods presented. Although we currently are not engaged in any arrangements that would be effected by these disclosure requirements, we believe that ASU 2011-11 may have a material impact on future disclosures pending our entrance into an offsetting arrangement.

In May 2011, the FASB issued ASU 2011-04, *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS*. ASU 2011-04 generally provides a uniform framework for fair value measurements and related disclosures between GAAP and International Financial Reporting Standards ("IFRS"). Additional disclosure requirements in the update include: (1) for Level 3 fair value measurements, quantitative information about unobservable inputs used, a description of the valuation process used by the entity, and a qualitative discussion about the sensitivity of the measurements to changes in the unobservable inputs; (2) for an entity's use of a nonfinancial asset that is different from the asset's highest and best use, the reason for the difference; (3) for financial instruments not measured at fair value but for which disclosure of fair value is required, the fair value hierarchy level in which the fair value measurements were determined; and (4) the disclosures of all transfers between Level 1 and Level 2 of the fair value hierarchy. This update is effective for annual and interim periods beginning on or after December 31, 2011. We adopted ASU 2011-04 on January 1, 2012, with no material impact.

In December 2010, the FASB issued ASU 2010-29, *Disclosure of Supplementary Pro Forma Information for Business Combinations* ("ASU 2010-29"). The amendments to the codification clarify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. Additionally, the supplemental pro forma disclosures under Topic 805 have been expanded to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The amendments in ASU 2010-29 are effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. Although we have not entered into any significant business combinations in our recent history, we believe that ASU 2010-29 may have a material impact on future disclosures depending on the size and nature of any future business combinations that we may enter into. We adopted ASU 2010-29 on January 1, 2011.

3. BUSINESS SEGMENT INFORMATION

In 2012, we changed the structure of our internal organization causing a change in the composition of our segments. Accordingly, we have restated the items of segment information for earlier periods to reflect the change in our internal organization, as described in our Current Report on Form 8-K, filed on November 12, 2012.

We have two principal reportable segments, which are segregated based on the products and services that each provide: (a) exploration and production, and (b) field services. Our exploration and production segment engages in the exploration, acquisition, development and production of oil, natural gas and NGLs. Our field services segment operates and manages water sourcing, water transfer and water disposal services, primarily in the Appalachian Basin.

We evaluate the performance of our business segments based on net income (loss) from continuing operations, before income taxes. All intercompany transactions, including those between consolidated business segments, are eliminated in consolidation. Summarized financial information concerning our segments is shown in the following table for 2012, 2011 and 2010 (in thousands):

	Exploration and Production	Field Services	Intercompany Eliminations	Consolidated Total
For the Year Ended December 31, 2012				
Revenues	$ 134,736	$15,637	$(2,234)	$ 148,139
Inter-Segment Revenues	0	(2,234)	2,234	0
Total Revenues	134,736	13,403	0	148,139
Depreciation, Depletion and Amortization	44,955	482	0	45,437
Impairment Expense	20,505	80	0	20,585
Other Operating Expense(a)	76,063	10,859	(1,723)	85,199
Interest Expense(b)	6,424	26	0	6,450
Other (Income) Expense(c)	(105,426)	0	104	(105,322)
Income (Loss) From Continuing Operations, Before Income Taxes	$ 92,215	$ 1,956	$ 1,619	$ 95,790
Total Assets	$ 766,599	$12,166	$(6,055)	$ 772,710
Expenditures for Long-Lived Assets	$ 227,913	$ 3,134	$ (707)	$ 230,340
Equity Method Investments	$ 16,978	$ 0	$ 0	$ 16,978
For the Year Ended December 31, 2011				
Revenues	$ 112,088	$ 3,546	$(1,028)	$ 114,606
Inter-Segment Revenues	0	(1,028)	1,028	0
Total Revenues	112,088	2,518	0	114,606
Depreciation, Depletion and Amortization	27,670	186	0	27,856
Impairment Expense	14,316	315	0	14,631
Other Operating Expense(a)	59,917	3,169	(756)	62,330
Interest Expense(b)	2,523	1	0	2,524
Other (Income) Expense(c)	(19,021)	(100)	35	(19,086)
Income (Loss) From Continuing Operations, Before Income Taxes	$ 26,683	$ (1,053)	$ 721	$ 26,351
Total Assets	$ 600,049	$ 7,143	$(5,641)	$ 601,551
Expenditures for Long-Lived Assets	$ 269,823	$ 5,571	$ 0	$ 275,394
Equity Method Investments	$ 41,683	$ 0	$ 0	$ 41,683
For the Year Ended December 31, 2010				
Revenues	$ 67,397	$ 1,718	$ (352)	$ 68,763
Inter-Segment Revenues	0	(352)	352	0
Total Revenues	67,397	1,366	0	68,763
Depreciation, Depletion and Amortization	21,422	146	0	21,568
Impairment Expense	8,424	439	0	8,863
Other Operating Expense(a)	27,820	1,538	(37)	29,321
Interest Expense(b)	1,308	0	0	1,308
Other (Income) Expense(c)	(5,602)	0	0	(5,602)
Income (Loss) From Continuing Operations, Before Income Taxes	$ 14,025	$ (757)	$ 37	$ 13,305
Total Assets	$ 405,066	$ 2,019	$ 0	$ 407,085
Expenditures for Long-Lived Assets	$ 149,075	$ 1,323	$ 0	$ 150,398
Equity Method Investments	$ 18,399	$ 0	$ 0	$ 18,399

(a) Includes the following expenses: production and lease operating expenses, general and administrative expenses, (gain) loss on disposal of assets, exploration expenses, field services operating expenses and other operating expense.
(b) Totals will not agree to Consolidated Statements of Operations due to exclusion of immaterial amounts of interest income, which is included in Other (Income) Expense.
(c) Includes the following expenses: interest income, gain (loss) on derivative, net, other income (expense) and gain (loss) on equity method investments.

4. BUSINESS AND OIL AND GAS PROPERTY ACQUISITIONS AND DISPOSITIONS

Acquisitions

We have made no significant acquisitions for the years ended December 31, 2012, 2011 and 2010.

Dispositions

Keystone Midstream Services, LLC

On May 29, 2012, we closed the sale of our ownership in Keystone Midstream Services, LLC ("Keystone Midstream"), which we had accounted for as an equity method investment. The base consideration for the sale was $483.2 million after adjustments for closing cash, working capital and outstanding debt. Our net proceeds at closing totaled $121.4 million, net of $3.3 million for our share of transactional costs which we recorded as Gain (Loss) on Equity Method Investments on our Consolidated Statement of Operations. During the third quarter of 2012, we recorded $0.5 million of post-closing settlement charges that we expect to incur, effectively decreasing our net proceeds to approximately $120.9 million. We have used the proceeds to pay down amounts outstanding under our Senior Credit Facility and for working capital. The amount received at closing excluded approximately $14.3 million held in escrow to be paid out over the course of the 12 months following closing. During the fourth quarter of 2012 we received approximately $7.2 million of the outstanding escrow amount. Any remaining escrow amounts received will be recognized in income when received. Also included in the proceeds at closing was approximately $3.8 million funded by other sellers in the transaction as consideration for our entry into an amendment to one of our gas gathering, compression and processing agreements. This consideration is recorded as Other Deposits and Liabilities on our Consolidated Balance Sheet and will be recognized in earnings over the term of the gas gathering, compression and processing agreement. We recognized a gain on the sale of our investment of Keystone Midstream, including the post-closing adjustment of $0.5 million and the receipt of the escrow funds of $7.2 million, of $99.4 million, all of which was recorded as Other Income (Expense) in our Consolidated Statement of Operations. See Note 7, *Equity Method Investments*, to our Consolidated Financial Statements for additional information on Keystone Midstream.

Sumitomo Joint Venture

On September 30, 2010, we entered into a joint venture transaction with an affiliate of Sumitomo Corporation ("Sumitomo"). In Butler County, Pennsylvania we sold a 15% non-operated interest in approximately 40,700 net acres for approximately $30.6 million in cash at closing and $30.6 million in the form of a drilling carry of 80% of our drilling and completion costs in the area. Pursuant to the Participation and Exploration Agreement (the "Sumitomo PEA"), Sumitomo agreed to pay all of the costs to lease approximately 9,000 net acres in the Butler County Area of Mutual Interest ("AMI") (the "Phase I Leasing"), and to pay to us a leasing management fee of $1,000 per net acre during the Phase I Leasing. The Phase I Leasing and drilling carry for Butler County were completed during the first quarter of 2011, resulting in final ownership percentages of 70% to us and 30% to Sumitomo. The cost of future leasing activities will be shared on a 70/30 basis, with Sumitomo paying to us a management fee of $150 per net acre acquired. In addition to the sale of undeveloped acreage, we also sold to Sumitomo 30% of our interests in 20 Marcellus Shale wells within the Butler County area and 30% of our interest in Keystone Midstream (for additional information on Keystone Midstream, see Note 7, *Equity Method Investments*, to our Consolidated Financial Statements).

In our Marcellus Shale joint venture project areas with WPX Energy San Juan, LLC (formerly known as Williams Production Company, LLC) and Williams Production Appalachia, LLC (collectively, "Williams"), which was entered into in 2009, we sold to Sumitomo 20% of our interests in 23,500 net acres for approximately $19.0 million in cash at closing and $19.0 million in the form of a drilling carry of 80% of our drilling and completion costs in the areas. In addition, we sold 20% of our interests in 19 Marcellus Shale wells located in the Williams joint venture areas and 20% of our interest in RW Gathering, LLC ("RW Gathering") (for additional information on RW Gathering, see Note 7, *Equity Method Investments*, to our Consolidated Financial Statements).

In addition to the areas above, we sold to Sumitomo 50% of our interests in approximately 4,500 net acres in Fayette and Centre Counties, Pennsylvania for $9.2 million in cash at closing and $9.2 million in the form of a drilling carry of 80% of our drilling and completion costs. Pursuant to the Sumitomo PEA, the drilling carry for these areas was to be applied, at our discretion, to drilling and completion costs attributable to either the Butler County or Williams joint venture areas. We elected to apply these drilling carries to other costs as permitted under the PEA, and consequently, as of December 31, 2011, there were no remaining drilling carries with Sumitomo.

At closing, we received approximately $99.5 million in cash, which included a reimbursement for leasing expenses incurred subsequent to the effective date of September 1, 2010, in the amount of approximately $7.6 million. Additionally, the cash payment included a reimbursement for drilling related expenses incurred subsequent to the effective date in the amount of approximately $7.5 million, which was applied against the drilling carry. Pursuant to industry rules, we do not make any accounting for the carried amounts paid on our behalf by Sumitomo. We recognized a gain of approximately $16.5 million on the Sumitomo transaction which is classified as (Gain) Loss on Disposal of Asset on our Consolidated Statement of Operations.

5. DISCONTINUED OPERATIONS/ASSETS HELD FOR SALE

During December 2011, our board of directors approved a formal plan to sell our DJ Basin assets located in the states of Wyoming and Colorado. During 2012, we sold various parcels of acreage throughout our DJ Basin holdings at varying prices, much of which was lower than the existing carrying value of similar remaining acreage at the time of sale. Market conditions in the region for similar assets have experienced a deterioration of price over the course of the last 12 months to which we have responded by modifying our marketing efforts. The assets remaining are available for immediate sale pending normal due diligence incurred during the course of normal business, with a sale expected within one year. The recording of Depreciation, Depletion, Amortization and Accretion ("DD&A") expense related to our DJ Basin assets ceased in December 2011. During 2012, we continually evaluated the value, less cost to sell, of our DJ Basin assets and determined that the fair value of our assets was less than the carrying amount of the assets based on recent purchase and sale activities in the Basin. In total, we incurred approximately $19.8 million in Impairment Expense related to the write down of our DJ Basin assets during 2012. For additional information on impairment, see Note 18, *Impairment Expense*, to our Consolidated Financial Statements.

These assets were classified as Assets Held for Sale on our Balance Sheet as of December 31, 2012 and December 31, 2011, and the results of operations are reflected in Discontinued Operations in our Consolidated Statements of Operations. We included $2.3 million and $24.8 million of net assets located in the DJ Basin as Assets Held for Sale on our Consolidated Balance Sheets as of December 31, 2012 and 2011, respectively. We included approximately $0.1 million and $1.6 million of liabilities as Liabilities Related to Assets Held for Sale on our Consolidated Balance Sheets as of December 31, 2012 and 2011, respectively. These liabilities primarily relate to Accounts Payable and Accrued Expenses. Upon the completion of a sale, we will have no continuing activities in the DJ Basin or continuing cash flows from this region. For additional information on our remaining DJ Basin assets, see Note 26, *Subsequent Events*, to our Consolidated Financial Statements.

Summarized financial information for Discontinued Operations is set forth in the table below, and does not reflect the costs of certain services provided. Such costs, which were not allocated to the Discontinued Operations, were for services, including legal counsel, insurance, external audit fees, payroll processing, certain human resource services and information technology systems support.

	December 31,		
($ in thousands)	2012	2011	2010
Revenues:			
Oil and Gas Sales	$ 97	$ 556	$ 0
Total Operating Revenue	97	556	0
Costs and Expenses:			
Production and Lease Operating Expense	353	493	0
General and Administrative Expense	660	1,745	782
Exploration Expense	867	33,812	2,664
Impairment Expense	19,770	13,177	0
Depreciation, Depletion, Amortization and Accretion	0	85	1
Other Operating Expense	8	1	0
Gain on Disposal of Asset	(2,126)	0	0
Interest Expense	0	1	0
Other (Income) Expense	(3)	1	0
Total Costs and Expenses	19,529	49,315	3,447
Income (Loss) from Discontinued Operations Before Income Taxes	(19,432)	(48,759)	(3,447)
Income Tax (Expense) Benefit	8,489	15,302	1,425
Income (Loss) from Discontinued Operations, Net of Income Taxes	$(10,943)	$(33,457)	$(2,022)
Production			
Crude Oil (Bbls)	1,272	6,939	0

6. CONSOLIDATED SUBSIDIARIES

Our consolidated subsidiaries make up 100.0% of our field services segment. For additional information, see Note 3, *Business Segment Information*, to our Consolidated Financial Statements.

Water Solutions Holdings

In November 2009, we entered into a limited liability agreement with Sand Hills Management, LLC ("Sand Hills") to form Water Solutions Holdings, LLC ("Water Solutions") for the purpose of acquiring, managing and operating water treatment, disposal and transportation facilities that are designed to treat, dispose or transport brine and fresh waters used and produced in oil and gas well development activities. The members of Water Solutions are Rex Energy Corporation, which owns an 80% membership interest, and Sand Hills, which owns a 20% membership interest and serves as the operator of the entity. Upon the return of our initial investments in Water Solutions, plus interest, our ownership percentage will change to 60% and the remaining 40% will be held by Sand Hills.

We fully consolidate the accounts of Water Solutions in our financial statements and account for the 20% equity interest owned by Sand Hills as a noncontrolling interest. Water Solutions is financed through cash contributions from its members and a credit facility upon which $0.7 million was drawn as of December 31, 2012. Water Solutions' credit facility did not exist at December 31, 2011. There were no cash contributions during the 12 months ending December 31, 2012, and cash contributions during the 12 months ending December 31, 2011 were negligible. The table below sets forth the carrying amount and classifications of Water Solutions' assets and liabilities as of December 31, 2012 and 2011, with no restrictions or obligations to use certain assets to settle associated liabilities:

($ in thousands)	December 31, 2012	December 31, 2011
Assets		
Cash and Cash Equivalents	$ 741	$ 374
Accounts Receivable	3,360	877
Inventory, Prepaid Expenses and Other	13	11
Other Property and Equipment	3,560	561
Wells and Facilities in Progress	221	134
Accumulated Depreciation, Depletion and Amortization	(501)	(75)
Deferred Financing Costs and Other Assets—Net	199	192
Total Assets	$7,593	$2,074
Liabilities		
Accounts Payable	$1,554	$ 481
Accrued Expenses	1,036	119
Senior Secured Line of Credit and Long-Term Debt	965	100
Total Liabilities	$3,555	$ 700

NorthStar #3, LLC

In August 2011, our wholly owned subsidiary, R.E. Gas Development, LLC ("R.E. Gas") and NorthStar Water Management ("NorthStar") formed NorthStar #3, LLC ("NorthStar #3") to construct, own and operate a water disposal well in Mahoning County, Ohio. At December 31, 2012, R.E. Gas owned a 51% membership interest in NorthStar #3 and serves as the operator of the entity; the remaining 49% membership interest was owned by NorthStar. To supplement the operations of NorthStar #3, the entity entered into a promissory note with us. As of December 31, 2012 and 2011, the amount owed to us under the promissory note was $4.6 million and $4.9 million, respectively (for additional information see Note 10, *Related Party Transactions*, to our Consolidated Financial Statements).

A variable interest entity ("VIE") is an entity that by design has insufficient equity to permit it to finance its activities without additional subordinated financial support or equity holders that lack the characteristics of a controlling financial interest. Based on these factors we have determined NorthStar #3 to be a VIE.

We are considered the primary beneficiary of the entity and have consolidated the financial results. To be considered the primary beneficiary, a member must have the power to direct the activities that most significantly impact the entity's performance and have a significant variable interest that carries with it the obligation to absorb the losses or the right to receive benefits. The activities that most significantly impact the entity's economic performance relate to the drilling of a successful disposal well with ample capacity and the ongoing operation of the well. Per the membership agreement, we hold a first right of refusal on all capacity rights for the disposal well, giving us the ability to make decisions regarding the operation and capacity of the well based on market conditions and, thus, the ability to direct the activities that most significantly impact the economic performance of the entity. We hold a significant variable interest in the entity in the form of our 51% membership interest and the $4.6 million promissory note. We have no recourse to recover the amount of the promissory note in the event that the disposal well is unsuccessful, leaving us with the obligation to absorb the losses. Upon success of the disposal well, we will initially have the right to approximately 87.3% of the available cash at the end of the period which covers the repayment of the note and our membership interest.

The carrying amount and classifications of NorthStar #3 assets and liabilities as of December 31, 2012 and December 31, 2011 are as follows, with no restrictions or obligations to use certain assets to settle associated liabilities:

	December 31,	
($ in thousands)	2012	2011
Assets		
Cash and Cash Equivalents	$ 14	$ 10
Wells and Facilities in Progress	4,559	5,059
Total Assets	$4,573	$5,069
Liabilities		
Accounts Payable	$ 6	$ 134
Note Payable	4,633	4,935
Total Liabilities	$4,639	$5,069

7. EQUITY METHOD INVESTMENTS

RW Gathering

RW Gathering, LLC ("RW Gathering") is a Delaware limited liability company that we jointly own with WPX Energy Inc. ("WPX") and Sumitomo, with our ownership equaling 40%. RW Gathering owns gas-gathering and other midstream assets that service jointly owned properties in Westmoreland and Clearfield Counties, Pennsylvania.

We recorded our investment in RW Gathering of approximately $17.0 million and $15.7 million as of December 31, 2012 and 2011, respectively, on our Consolidated Balance Sheets as Equity Method Investments. During 2012, we contributed approximately $2.0 million in cash to RW Gathering to support current pipeline and gathering line construction, compared to $9.7 million during the same period in 2011. RW Gathering recorded net losses from continuing operations of $1.7 million, $0.4 million and $0.1 million for the years ended December 31, 2012, 2011 and 2010, respectively. The losses incurred were due to insurance fees, bank fees, rent expenses and DD&A expense. Our share of the net loss from continuing operations is recorded on the Statements of Operations as Loss on Equity Method Investments.

When evaluating our Equity Method Investments for impairment we review our ability to recover the carrying amount of such investments or the entity's ability to sustain earnings that justify its carrying amount. In the case of RW Gathering, the nature of its assets is such that under normal circumstances an entity would capitalize and evaluate the assets as a part of its producing well properties. Therefore, our ability to recover the carrying amount of our investment lies in the value of our producing well assets that utilize these gathering systems. As of December 31, 2012, we determined that we had the ability to recover the carrying amount of our investment in RW Gathering.

Keystone Midstream

On May 29, 2012, we closed the sale of our ownership in Keystone Midstream, which we had accounted for as an equity method investment. For additional information on the sale of Keystone Midstream, see Note 4, *Business and Oil and Gas Property Acquisitions and Dispositions*, to our Consolidated Financial Statements.

Prior to May 29, 2012, we owned a 28% non-operating interest in Keystone Midstream, which was a midstream joint venture focused on building, owning and operating high pressure gathering systems and cryogenic gas processing plants in Butler County, Pennsylvania. We recorded our investment in Keystone Midstream of approximately $28.1 million as of the date of sale and $26.0 million as of December 31, 2011, on our Consolidated Balance Sheets as Equity Method Investments. In 2012 and 2011, we contributed approximately $2.1 million and $13.5 million, respectively, to Keystone Midstream primarily to support the construction of cryogenic gas processing plants. Keystone Midstream recorded a net loss from continuing operations of $12.0 million as of May 29, 2012, net income of $1.6 million as of December 31, 2011 and a net loss of $0.5 million for the four-month period ended December 31, 2010. Included in the net loss recorded in 2012 were approximately $12.0 million of transaction expenses related to the sale of the entity. Prior to September 1, 2010, we consolidated the operations of Keystone Midstream, where the noncontrolling interest's share of net loss was recorded as Net Loss Attributable to Noncontrolling Interests. Our share of net income and net loss realized under the equity method of accounting are primarily due to project management costs, general and administrative expenses, and DD&A expenses and totaled approximately $3.2 million of net loss, $0.5 million of net income and $0.1 million of net loss for the period ended May 29, 2012, for the year ended December 31, 2011 and for the four-month period ended December 31,2010, respectively.

8. CONCENTRATIONS OF CREDIT RISK

At times during the years ended December 31, 2012 and 2011, our cash balance may have exceeded the Federal Deposit Insurance Corporation's limit of $250,000. There were no losses incurred due to such concentrations.

By using derivative instruments to hedge exposure to changes in commodity prices, we are exposed to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of the derivative is positive, the counterparty owes us, which creates repayment risk. We minimize the credit or repayment risk in derivative instruments by entering into transactions with four high-quality counterparties. Our counterparties are investment grade financial institutions, and lenders in our Senior Credit Facility. We have a master netting agreement in place with our counterparties that provides for the offsetting of payables against receivables from separate derivative contracts. None of our derivative contracts have a collateral provision that would require funding prior to the scheduled settlement date. For additional information, see Note 2, *Summary of Significant Accounting Policies,* and Note 12, *Fair Value of Financial Instruments and Derivative Instruments,* to our Consolidated Financial Statements.

We also depend on a relatively small number of purchasers for a substantial portion of our revenue. At December 31, 2012, we carried approximately $18.1 million in production receivables, of which approximately $16.3 million were production receivables due from four purchasers. At December 31, 2011, we carried approximately $13.6 million in production receivable, of which approximately $12.9 million were production receivables due from three purchasers. We believe the growth in our Appalachian estimated proved reserves will help us to minimize our future risks by diversifying our ratio of oil and gas sales as well as the quantity of purchasers.

9. COMMITMENTS AND CONTINGENCIES

Legal Reserves

We are involved in various legal proceedings that arise in the ordinary course of our business. Although we cannot predict the outcome of these proceedings with certainty, we do not currently expect these matters to have a material adverse effect on our consolidated financial position or results of operations.

As of December 31, 2012 and 2011, we did not have any reserves established for future legal obligations. The establishment of a reserve involves an estimation process that includes the advice of legal counsel and the subjective judgment of management. While we currently believe that no reserve is needed, there are uncertainties associated with legal proceedings and we can give no assurance that our estimate of any related liability will not increase or decrease in the future. The unreserved exposures for our legal proceedings could change based upon developments in those proceedings or changes in the facts and circumstances. It is possible that we could incur future losses that are not currently accrued. Based on currently available information, we believe that it is remote that future costs, if any, would have a material adverse effect on our consolidated financial position, although cash flow could be significantly impacted in the reporting periods in which such costs are incurred.

Environmental

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

We manage our exposure to environmental liabilities on properties to be acquired by conducting evaluations (both internal and using consultants) to identify existing problems and assessing the potential liability. Except for contingent liabilities associated with the consent decree with the U.S. EPA relating to alleged H_2S emissions in the Lawrence Field, we know of no significant probable or possible environmental contingent liabilities.

Letters of Credit

We have posted $0.8 million, at December 31, 2012 and December 31, 2011, in various letters of credit to secure our drilling and related operations.

Lease Commitments

At December 31, 2012 we have lease commitments for various real estate leases. Rent expense from continuing operations has been recorded in General and Administrative expense as $0.3 million, $0.4 million and $0.3 million for the years ended December 31, 2012, 2011 and 2010, respectively. Lease commitments by year for each of the next five years are presented in the table below ($ in thousands).

2013	$ 551
2014	463
2015	420
2016	420
2017	420
Thereafter	0
Total	$2,274

Capacity Reservation

In connection with our sale of Keystone Midstream (see Note 7, *Equity Method Investments*, to our Consolidated Financial Statements), we entered into a capacity reservation arrangement with a subsidiary of MarkWest Energy Partners, L.P. ("MarkWest") to ensure sufficient capacity at the cryogenic gas processing plants owned by MarkWest to process our produced natural gas. In the event that we do not process any gas through the cryogenic gas processing plants, we may be obligated to pay approximately $6.1 million in 2013, $10.4 million in 2014, $13.0 million in 2015, $14.6 million in 2016, $14.6 million in 2017 and $115.3 million thereafter. For the years ended December 31, 2010, 2011 and 2012, we incurred capacity reservation charges of

$0 million, $0.1 million and $0.5, respectively, which is consistent with our estimated working interest in this project area of approximately 70.0%. Charges for the capacity reservation are recorded as Production and Lease Operating Expense on our Consolidated Statements of Operations.

Operational Commitments

Pursuant to agreements reached during the fourth quarter of 2010 and the first quarter of 2011, and amended during the third quarter of 2012, we have contracted drilling rig services on two rigs to support our Appalachian Basin operations. The minimum cost to retain these rigs would require payments of approximately $3.0 million in 2013, $3.0 million in 2014 and $0.8 million in 2015, which is consistent with our estimated working interest in this project area. In addition, during the first quarter of 2011, we came to terms on contracted completion services in the Appalachian Basin. The minimum cost to retain the completion services is approximately $8.4 million in 2013 and $2.1 million in 2014, which is consistent with our estimated working interest in this project area.

Natural Gas Gathering, Processing and Sales Agreements

During the normal course of business we have entered into certain agreements to ensure the gathering, transportation, processing and sales of specified quantities of our oil, natural gas and NGLs. In some instances, we are obligated to pay shortfall fees, whereby we would pay a fee for any difference between actual volumes provided as compared to volumes that have been committed. In other instances, we are obligated to pay a fee on all volumes that are subject to the related agreement. In connection with our entry into certain of these agreements, we concurrently entered into a guaranty whereby we have guaranteed the payment of obligations under the specified agreements up to a maximum of $406.4 million, which is larger than our estimated minimum obligations due to certain contracts which have minimum commitment volumes and other contracts which contain provisions that require payment on all volumes delivered.

For the years ended December 31, 2012, 2011 and 2010, we incurred expenses related to the transportation and marketing our oil, natural gas and natural gas liquids of approximately $9.0 million, $4.6 million and $0.1 million, respectively.

Minimum net obligations under these sales, gathering and transportation agreements for the next five years are as follows ($ in thousands):

	Total
2013	$ 8,411
2014	12,495
2015	19,584
2016	26,712
2017	32,552
Thereafter	341,576
Total	$441,330

Drilling Commitments

During the first quarter of 2012, we entered into a drill-to-earn agreement with MFC Drilling, Inc. ("MFC"). Under the terms and conditions of the agreement, we will acquire at a minimum, through a drill-to-earn structure, a 62.5% working interest in approximately 4,510 acres in Belmont, Guernsey and Noble Counties, Ohio. The agreement provides that in order for us to earn the 62.5% working interest, we will bear the cost for our 62.5% working interest and 100% of the 15% working interest of MFC until such time that we have met the $14.1 million drilling carry obligation. As of December 31, 2012, the remaining drilling carry obligation balance was approximately $11.3 million.

In addition to the drilling carry obligation, we are required to meet certain drilling commitments. Amounts incurred toward the attainment of the drilling commitments are credited towards the drilling carry obligation. Our drilling commitments require us to commence the drilling of at least three Utica Shale wells by November 15 of each year until the carry obligation has been satisfied, with credits given to additional wells drilled beyond the annual commitment. We currently estimate the commitment for each well drilled and completed for our working interest and that of MFC to be approximately $8.0 million to $9.0 million. We have until the earlier of (i) six months from the first date of sales and (ii) June 15, 2013 to terminate the agreement. Should we not comply with the drilling commitments or terminate the agreement outside of the aforementioned termination parameters, we would be responsible for payment of the remaining drilling carry obligation at that time.

Pennsylvania Impact Fee

During the first quarter of 2012, Pennsylvania state legislators instituted a natural gas impact fee on producers of unconventional natural gas. The fee will be imposed on every producer of unconventional natural gas and applies to unconventional wells spud in Pennsylvania regardless of when spudding occurred. Unconventional gas wells that were spud prior to 2012 are considered to be spud in 2011 for purposes of determining the fee, which is considered year one for those wells. The fee for each unconventional natural gas well is determined using the following matrix, with vertical unconventional natural gas wells being charged 20% of the applicable rates:

	<$2.25(a)	$2.26 - $2.99(a)	$3.00 - $4.99(a)	$5.00 - $5.99(a)	>$5.99(a)
Year One	$40,000	$45,000	$50,000	$55,000	$60,000
Year Two	$30,000	$35,000	$40,000	$45,000	$55,000
Year Three	$25,000	$30,000	$30,000	$40,000	$50,000
Year 4—10	$10,000	$15,000	$20,000	$20,000	$20,000
Year 11—15	$ 5,000	$ 5,000	$10,000	$10,000	$10,000

(b) Pricing utilized for determining annual fees is based on the arithmetic mean of the NYMEX settled price for the near-month contract as reported by the Wall Street Journal for the last trading day of each month of a calendar year for the 12-month period ending December 31.

For the twelve months ended December 31, 2012, we incurred approximately $5.4 million in fees related to the natural gas impact fee. Of this amount, approximately $2.8 million was related to the first year fees for unconventional gas wells drilled prior to 2012. We have recorded these fees as Production and Lease Operating Expense on our Consolidated Statement of Operations.

Other

In addition to the asset retirement obligation discussed in Note 2, *Summary of Significant Accounting Policies*, we have withheld from distributions to certain other working interest owners amounts to be applied towards their share of those retirement costs. Such amounts, totaling $0.3 million, are included in Other Deposits and Liabilities at December 31, 2012 and December 31, 2011, respectively.

10. RELATED PARTY TRANSACTIONS

Aircraft Services

We have an oral month-to-month agreement with Charlie Brown Air Corp. ("Charlie Brown"), a New York corporation owned by Lance T. Shaner, our Chairman, regarding the use of two airplanes owned or managed on our behalf by Charlie Brown. Under our agreement with Charlie Brown, we pay a monthly fee for the right to use the airplanes equal to our percentage (based upon the total number of hours of use of the airplanes by us) of the monthly fixed costs for the airplanes, plus a variable per hour flight rate that ranges from $400 to $1,850 per hour. In September 2010, we purchased an undivided 50% interest in one of these airplanes, a Cessna model 550 from Charlie Brown for approximately $0.6 million. In April 2011, we purchased the remaining 50% interest in this aircraft for approximately $0.6 million. The purchase of the aircraft has been recorded as Other Property and Equipment on our Consolidated Balance Sheets. For the years ended December 31, 2011 and 2010, we paid Charlie Brown $0.2 million and $0.4 million, respectively, for the use of the aircrafts, including the variable per hour cost in addition to pilots fees, maintenance, hangar rental and other miscellaneous expenses. For the year ended December 31, 2012, the amounts paid to Charlie Brown were negligible.

We own a 25% membership interest in Charlie Brown Air II, LLC ("Charlie Brown II"). Shaner Hotel Group Limited Partnership, a Delaware limited partnership controlled by Mr. Lance T. Shaner ("Shaner Hotel"), and an unrelated third party each own 25% and 50%, respectively, in Charlie Brown II, which owns and operates an Eclipse 500 aircraft, which was purchased for approximately $1.7 million.

Charlie Brown II has a loan from Susquehanna Bank, formerly Graystone Bank, to purchase the aircraft that was originally $1.5 million at its inception in June 2007. The loan matures on June 21, 2017 and bears interest at a rate of LIBOR plus 2.5%. The loan required payments of interest only for the first three months of the loan. Thereafter, Charlie Brown II has been required to make monthly payments of principal and interest utilizing an amortization period of 180 months. The Company and Shaner Hotel each guarantee up to twenty five percent, or $0.4 million, of the principal balance of the loan. The balance of this loan as of December 31, 2012 and 2011 was approximately $1.3 million and $1.4 million, respectively. For the years ended December 31, 2012, 2011 and 2010, we paid Charlie Brown II approximately $0.2 million each year, respectively, for loan interest, services rendered and retainer fees.

The business affairs of Charlie Brown Air II, LLC are managed by three members, appointed by each of its three owners. We have designated Thomas C. Stabley, our Chief Executive Officer, as the manager representing our membership interest. Actions of the company must be approved by a majority of the interest percentages of the managers. Each manager votes in matters before the company in accordance with the membership interest percentage of the member that appointed the manager. Certain events, such as the sale by a member of its interest, the merger or consolidation of the company, the filing of bankruptcy, or the sale of the airplane owned by Charlie Brown Air II, LLC, require the written consent of all managers. The consent of managers is also required before the company may change or terminate the management agreement with Charlie Brown, incur any indebtedness, sell substantially all of the company's assets or sell the airplane owned by the company. In the event that the members are unable to unanimously agree upon any of these matters within 10 days of the proposal of any such matter, an "impasse" may be declared, and the airplane will be sold by the company.

Office Rental

On June 27, 2012, we entered into an office lease agreement with Shaner Office Holdings, L.P., a limited partnership controlled by Lance T. Shaner. The office lease, which will replace our existing headquarters office lease in State College, Pennsylvania, calls for monthly rental payments in the amount of $35,000 beginning on April 1, 2013 and ending on December 31, 2017, with an annual Consumer Price Index ("CPI") adjustment. The annual CPI adjustment is capped at 2.5%. The term of the lease may be extended for up to three five-year extensions or the property may be purchased outright by our exercise of a purchase option at the end of the five-year lease term. We will account for this lease as an operating lease, subsequently recording the rental payments as General and Administrative Expense on our Consolidated Statements of Operations.

RW Gathering, LLC

We own a 40% interest in RW Gathering which owns gas-gathering assets to facilitate the development of our joint operations with WPX and Sumitomo (see Note 7, *Equity Method Investments*, to our Consolidated Financial Statements). For the years ended December 31, 2012, 2011 and 2010, we incurred approximately $0.8 million, $0.8 million and $0.2 million, respectively, in compression expenses that were charged to us from Williams Production Appalachia, LLC. These costs are in relation to compression costs incurred by RW Gathering and are recorded as Production and Lease Operating Expense on our Consolidated Statement of Operations. As of December 31, 2012, 2011 and 2010, there were no receivables or payables in relation to RW Gathering due to or from us.

Keystone Midstream

We incurred approximately $2.4 million, $4.6 million and $0.3 million in transportation and processing expenses that were charged to us from Keystone Midstream during 2012, 2011 and 2010, respectively (see Note 7, *Equity Method Investments*, to our Consolidated Financial Statements). Prior to September 1, 2010, charges incurred for transportation were eliminated in consolidation. Subsequent to September 1, 2010, such transportation charges are recorded as Production and Lease Operating Expense on our Consolidated Statements of Operations. We sold our ownership interest in Keystone Midstream in May 2012, resulting in no amounts due to or from Keystone Midstream as of December 31, 2012. As of December 31, 2011, we had Accrued Expenses due to Keystone Midstream of approximately $0.5 million, which was inclusive of transportation and processing expenses incurred during December 2011.

Water Solutions

We incurred approximately $3.2 million, $1.6 million and $0.4 million in gross water transfer and water purification expenses that were charged to us from Water Solutions during 2012, 2011 and 2010, respectively (see Note 6, *Consolidated Subsidiaries*, to our Consolidated Financial Statements). Of the amounts incurred, we have eliminated approximately $2.2 million, $1.0 million and $0.4 million in consolidation for the years 2012, 2011 and 2010, respectively. As of December 31, 2012, 2011 and 2010, we had payables of approximately $0.2 million, $0.3 million and $0 to Water Solutions for work performed during the period.

NorthStar #3, LLC

During 2011, we paid approximately $4.9 million in expenses related to the drilling of a water disposal well on behalf of NorthStar #3 (see Note 6, *Consolidated Subsidiaries*, to our Consolidated Financial Statements). This amount has been recorded in a promissory note due to us from NorthStar #3. During 2012, we received approximately $0.3 million in refunds and reimbursements on expenditures previously incurred, decreasing the amount of the promissory note to approximately $4.6 million. The promissory note has been eliminated in consolidation, while the cost of the well has been recorded as Wells and Facilities in Progress on our Consolidated Balance Sheet. As of December 31, 2012 and 2011, there were no amounts due to NorthStar #3 or due to us from NorthStar #3 with exception to the promissory note. NorthStar #3 did not exist prior to 2011.

11. LONG-TERM DEBT

Senior Credit Facility

We maintain a revolving credit facility evidenced by the Credit Agreement, dated September 28, 2007, with KeyBank, as Administrative Agent; and lenders from time to time parties thereto (as amended from time to time, the "Senior Credit Facility"). Borrowings under the Senior Credit Facility are limited by a borrowing base that is determined in regard to our oil and gas properties. The borrowing base under the Senior Credit Facility is currently $240.0 million; however, the revolving credit facility may be increased to up to $500 million upon re-determinations of the borrowing base, consent of the lenders and other conditions prescribed in the agreement. The Senior Credit Facility provides that the borrowing base will be re-determined semi-annually by the lenders, in good faith, based on, among other things, reports regarding our oil and gas reserves attributable to our oil and gas properties, together with a projection of related production and future net income, taxes, operating expenses and capital expenditures. We may, or the Administrative Agent at the direction of a majority of the lenders may, each elect once per calendar year to cause the borrowing base to be re-determined between the scheduled re-determinations. In addition, we may request interim borrowing base re-determinations upon our proposed acquisition of proved developed producing oil and gas reserves with a purchase price for such reserves greater than 10% of the then borrowing base. As of December 31, 2012, loans made under the Senior Credit Facility were set to mature on September 28, 2015. In certain circumstances, we may be required to prepay the loans. Management does not believe that a prepayment will be required within the next twelve months. As of December 31, 2012, we did not have any amounts outstanding under the Senior Credit Facility as compared to $175.0 million at December 31, 2011.

Borrowings under the Senior Credit Facility bear interest, at our election, at the Adjusted LIBOR or the Alternative Base Rate (as defined below) plus, in each case an applicable per annum margin. The applicable per annum margin is determined based upon our total borrowing base utilization percentage in accordance with a pricing grid. The applicable per annum margin ranges from 1.75% to 2.75% for Eurodollar loans and .50% to 1.50% for ABR loans. The Adjusted Base Rate is equal to the greater of: (i) KeyBank's announced prime rate; (ii) the federal funds effective rate from time to time plus 1 / 2 of 1%; and (iii) LIBOR plus 1.25%. Our commitment fee is also dependent on our total borrowing base utilization percentage and is determined based upon an applicable per annum margin which ranges from 0.375% to 0.50%.

Under the Senior Credit Facility, we may enter into commodity swap agreements with counterparties approved by the lenders, provided that the notional volumes for such agreements, when aggregated with other commodity swap agreements then in effect (other than basis differential swaps on volumes already hedged pursuant to other swap agreements), do not exceed, as of the date the swap agreement is executed, 85% of the reasonably anticipated projected production from our proved developed producing reserves for the 36 months following the date such agreement is entered into, and 75% thereafter, for each of crude oil and natural gas, calculated separately. We may also enter into interest rate swap agreements with counterparties approved by the lenders that convert interest rates from floating to fixed provided that the notional amounts of those agreements, when aggregated with all other similar interest rate swap agreements then in effect, do not exceed the greater of $20 million and 75% of the then outstanding principal amount of our debt for borrowed money which bears interest at a floating rate.

The Senior Credit Facility contains covenants that restrict our ability to, among other things, materially change our business; approve and distribute dividends; enter into transactions with affiliates; create or acquire additional subsidiaries; incur indebtedness; sell assets; make loans to others; make investments; enter into mergers; incur liens; and enter into agreements regarding swap and other derivative transactions (for further information, see Note 2, *Summary of Significant Accounting Policies*, Note 8, *Concentrations of Credit Risk*, and Note 12, *Fair Value of Financial Instruments and Derivative Instruments*, to our Consolidated Financial Statements). Borrowings under the Senior Credit Facility have been used to finance our working capital needs and for general corporate purposes in the ordinary course of business, including the exploration, acquisition and development of oil and gas properties. Obligations under the Senior Credit Facility are secured by mortgages on the oil and gas properties of our subsidiaries located in the states of Pennsylvania, Illinois and Indiana. We are required to maintain liens covering our oil and gas properties representing at least 80% of our total value of all oil and gas properties.

The Senior Credit Facility also requires we meet, on a quarterly basis, minimum financial requirements of consolidated current ratio, EBITDAX to interest expense and total debt to EBITDAX. EBITDAX is a non-GAAP financial measure used by our management team and by other users of our financial statements, such as our commercial bank lenders, which adds to or subtracts from net income the following expenses or income for a given period to the extent deducted from or added to net income in such period: interest, income taxes, depreciation, depletion, amortization, unrealized gains and losses from derivatives, exploration expense and other similar non-cash activity. The Senior Credit Facility requires that as of the last day of any fiscal quarter, our ratio of consolidated current assets, which includes the unused portion of our borrowing base, as of such day to consolidated current liabilities as of such day, known as our current ratio, must not be less than 1.0 to 1.0. Our current ratio as of December 31, 2012 was approximately 6.0 to 1.0. Additionally, the Senior Credit Facility requires that as of the last day of any fiscal quarter, our ratio of EBITDAX for the current quarter on an annualized basis to interest expense for such period, known as our interest coverage ratio, must not be less than 3.0 to 1.0. Our interest coverage ratio as of December 31, 2012 was approximately 14.7 to 1.0. Additionally, as of the last day of any fiscal quarter, our ratio of total debt to EBITDAX for the current quarter on an annualized basis must not exceed 4.25 to 1.0. Our ratio of total debt to EBITDAX as of December 31, 2012 was approximately 2.4 to 1.0.

Second Lien Credit Agreement

On December 22, 2011, we entered into a second lien credit agreement (as amended from time to time, the "Second Lien Credit Agreement") with KeyBank, as administrative agent, Wells Fargo Bank, N.A., as syndication agent, UnionBanCal Equities, Inc. and SunTrust Bank, as co-documentation agents, and the lenders from time to time party thereto. The Second Lien Credit Agreement provided for a $100.0 million senior secured second lien term loan facility under which $50.0 million was initially available to us and up to an additional $50.0 million of incremental borrowings may be available upon the request of the Company. During December 2012, we repaid in full, and terminated, the Second Lien Credit Agreement. As of December 31, 2011, we had $50.0 million drawn on the Second Lien Credit Agreement.

Senior Notes

On December 12, 2012, we issued a $250.0 million aggregate principal amount of 8.875% senior notes in a private offering at an issue price of 99.3% due to mature on December 1, 2020 (the "Notes"). The net proceeds of the Notes, after discounts and expenses, were approximately $242.2 million. Debt issuance costs of $6.1 were recorded as Deferred Financing Costs and Other Assets – Net on our Consolidated Balance Sheet and are being amortized over the term of the notes as Interest Expense on our Consolidated Statement of Operations. Interest is payable semi-annually at a rate of 8.875% per annum on June 1 and December 1 of each year, commencing on June 1, 2013.

We may redeem, at specified redemption prices, some or all of the Notes at any time on or after December 1, 2016. We may also redeem up to 35% of the notes using the proceeds of certain equity offerings completed before December 1, 2015. If we sell certain of our assets or experience specific kinds of changes of control, we may be required to offer to purchase the notes from holders. The Notes will be fully and unconditionally guaranteed on a senior unsecured basis by certain of our existing and future domestic subsidiaries.

In addition to our Senior Credit Facility and our Notes, we may, from time to time in the normal course of business, finance assets such as vehicles, office equipment and leasehold improvements through debt financing at favorable terms. Long-term debt and lines of credit consists of the following at December 31, 2012 and 2011:

	December 31, 2012 (in thousands)	December 31, 2011 (in thousands)
8.875% Senior Notes	$250,000	$ 0
Discount on Senior Notes	(1,742)	0
Senior Lines of Credit and Second Lien(a)	0	225,000
Capital Leases and Other Obligations(a)	2,677	544
Total Debt	250,935	225,544
Less Current Portion of Long-Term Debt(b)	(1,686)	(406)
Total Long-Term Debt	$249,249	$225,138

(a) The average interest rate on borrowings under our Senior Credit Facility for the years ended December 31, 2012 and 2011 was approximately 2.5%. The average interest rate on borrowings under the Second Lien Credit Agreement for the year ended December 31, 2012 and 2011 was approximately 7.3% and 8.3%, respectively. The average interest rate on our Other Loans and Notes Payable as of December 31, 2012 and 2011 was approximately 4.5% and 2.3%, respectively.

(b) Classified as Accounts Payable on our Consolidated Balance Sheets.

The following is the principal maturity schedule for debt outstanding as of December 31, 2012:

	Year Ended December 31, (in thousands)
2013	$ 1,686
2014	378
2015	351
2016	262
2017	0
Thereafter	250,000
Total	$252,677

12. FAIR VALUE OF FINANCIAL INSTRUMENTS AND DERIVATIVE INSTRUMENTS

Our results of operations and operating cash flows are impacted by changes in market prices for oil, natural gas and NGLs. To mitigate a portion of the exposure to adverse market changes, we enter into oil, natural gas and NGL commodity derivative instruments to establish price floor protection. As such, when commodity prices decline to levels that are less than our average price floor, we receive payments that supplement our cash flows. Conversely, when commodity prices increase to levels that are above our average price ceiling, we make payments to our counterparties. We do not enter into these arrangements for speculative trading purposes. As of December 31, 2012, 2011 and 2010, our commodity derivative instruments consisted of fixed rate swap contracts, puts, collars, swaptions and three-way collars. We did not designate these instruments as cash flow hedges for accounting purposes. Accordingly, associated unrealized gains and losses are recorded directly as Gain on Derivatives, Net. For additional information, see Note 2, *Summary of Significant Accounting Policies*, to our Consolidated Financial Statements.

Swap contracts provide a fixed price for a notional amount of sales volumes. Collars contain a fixed floor price ("put") and ceiling price ("call"). The put options are purchased from the counterparty by our payment of a cash premium. If the put strike price is greater than the market price for a settlement period, then the counterparty pays us an amount equal to the product of the notional quantity multiplied by the excess of the strike price over the market price. The call options are sold to the counterparty, for which we receive a cash premium. If the market price is greater than the call strike price for a settlement period, then we pay the counterparty an amount equal to the product of the notional quantity multiplied by the excess of the market price over the strike price. A three-way collar is a combination of options, a sold call, a purchased put and a sold put. The purchased put establishes a minimum price unless the market price falls below the sold put, at which point the minimum price would be the settlement price plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price we will receive for the volumes under contract. Swaption agreements provide options to counterparties to extend swaps into subsequent years.

We enter into the majority of our derivative arrangements with four counterparties and have a netting agreement in place with these counterparties. We do not obtain collateral to support the agreements, but we believe our credit risk is currently minimal on these transactions. For additional information on the credit risk regarding our counterparties, see Note 8, *Concentrations of Credit Risk,* to our Consolidated Financial Statements.

None of our derivatives are designated for hedge accounting but are, to a degree, an economic offset to our commodity price exposure. We utilize the mark-to-market accounting method to account for these contracts. We recognize all unrealized and realized gains and losses related to these contracts in the Consolidated Statements of Operations as Gain on Derivatives, Net under Other Income (Expense).

We received net cash settlements of $16.2 million, $6.2 million and $0.1 million for the years ended December 31, 2012, 2011 and 2010, respectively. Unrealized gains and losses from continuing operations associated with our derivative instruments amounted to a loss of $5.5 million, a gain of $12.7 million and a gain of $6.0 million for the years ended December 31, 2012, 2011 and 2010, respectively.

The following table summarizes the location and amounts of gains and losses on derivative instruments from continuing operations, none of which are designated as hedges for accounting purposes, in our accompanying Consolidated Statements of Operations for the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31, 2012 (in thousands)		
	Realized Gains (Losses)	Unrealized Gains (Losses)	Total
Crude Oil			
Reclassification of settled contracts included in prior periods mark-to-market adjustments	$ 0	$ 2,138	$ 2,138
Mark-to-market fair value adjustments	0	(273)	(273)
Settlement of contracts(a)	(286)	0	(286)
Crude Oil Total	(286)	1,865	1,579
Natural Gas			
Reclassification of settled contracts included in prior periods mark-to-market adjustments	0	(10,404)	(10,404)
Mark-to-market fair value adjustments	0	2,471	2,471
Settlement of contracts(a)	16,095	0	16,095
Natural Gas Total	16,095	(7,933)	8,162
Natural Gas Liquids			
Reclassification of settled contracts included in prior periods mark-to-market adjustments	0	0	0
Mark-to-market fair value adjustments	0	536	536
Settlement of contracts(a)	410	0	410
Natural Gas Liquids Total	410	536	946
Gain (Loss) on Derivatives, Net	$16,219	$ (5,532)	$ 10,687

(a) These amounts represent the realized gains and losses on settled derivatives, which before settlement are included in the mark-to-market fair value adjustment

	Year Ended December 31, 2011 (in thousands)		
	Realized Gains (Losses)	Unrealized Gains (Losses)	Total
Crude Oil			
Reclassification of settled contracts included in prior periods mark-to-market adjustments	$ 0	$ 1,850	$ 1,850
Mark-to-market fair value adjustments	0	(1,488)	(1,488)
Settlement of contracts(a)	(670)	0	(670)
Crude Oil Total	(670)	362	(308)
Natural Gas			
Reclassification of settled contracts included in prior periods mark-to-market adjustments	0	(4,231)	(4,231)
Mark-to-market fair value adjustments	0	16,573	16,573
Settlement of contracts(a)	6,882	0	6,882
Natural Gas Total	6,882	12,342	19,224
Gain (Loss) on Derivatives, Net	$6,212	$12,704	$18,916

(a) These amounts represent the realized gains and losses on settled derivatives, which before settlement are included in the mark-to-market fair value adjustment.

	Year Ended December 31, 2010 (in thousands)		
	Realized Gains (Losses)	Unrealized Gains (Losses)	Total
Crude Oil			
Reclassification of settled contracts included in prior periods mark-to-market adjustments	$ 0	$ 5,782	$ 5,782
Mark-to-market fair value adjustments	0	(2,819)	(2,819)
Settlement of contracts(a)	(3,861)	0	(3,861)
Crude Oil Total	(3,861)	2,963	(898)
Natural Gas			
Reclassification of settled contracts included in prior periods mark-to-market adjustments	0	(1,925)	(1,925)
Mark-to-market fair value adjustments	0	4,211	4,211
Settlement of contracts(a)	4,667	0	4,667
Natural Gas Total	4,667	2,286	6,953
Interest Rate			
Reclassification of settled contracts included in prior periods mark-to-market adjustments	0	711	711
Mark-to-market fair value adjustments	0	0	0
Settlement of contracts(a)	(711)	0	(711)
Interest Rate Total	(711)	711	0
Gain (Loss) on Derivatives, Net	$ 95	$ 5,960	$ 6,055

(a) These amounts represent the realized gains and losses on settled derivatives, which before settlement are included in the mark-to-market fair value adjustment.

Our derivative instruments are recorded on the balance sheet as either an asset, or a liability, measured at its fair value. The fair value associated with our derivative instruments was an asset of approximately $9.8 million and $15.3 million at December 31, 2012 and 2011, respectively.

Our open asset/(liability) financial commodity derivative instrument positions at December 31, 2012 consisted of:

Period	Volume	Put Option	Floor	Ceiling	Swap	Fair Market Value ($ in Thousands)
Oil						
2013—Collar	540,000 Bbl	$ 0	$72.44	$112.56	$ 0	$ (217)
2013—Swap	120,000 Bbl	0	0	0	91.41	(217)
2013—Three Way Collar	60,000 Bbl	65.00	80.00	100.00	0	(45)
2014—Three Way Collar	360,000 Bbl	65.00	82.33	104.27	0	(509)
	1,080,000 Bbl					$ (988)
Natural Gas						
2013—Swap	6,570,000 Mcf	$ 0	$ 0	$ 0	$ 3.84	$ 1,631
2013—Three Way Collar	2,520,000 Mcf	3.35	4.17	4.88	0	986
2013—Collar	3,360,000 Mcf	0	4.77	5.68	0	4,211
2013—Put	2,640,000 Mcf	0	5.00	0	0	3,378
2013—Swaption	1,200,000 Mcf	0	0	0	4.50	354
2014—Call	1,800,000 Mcf	0	0	5.00	0	(366)
2014—Three Way Collar	4,800,000 Mcf	2.91	3.91	4.68	0	430
2014—Swap	2,400,000 Mcf	0	0	0	3.84	(195)
2014—Collar	1,800,000 Mcf	0	3.51	4.43	0	(166)
	27,090,000 Mcf					$10,263
Natural Gas Liquids						
2013—Swap	108,000 Bbl	$ 0	$ 0	$ 0	$43.26	$ 535
	108,000 Bbl					$ 535

The combined fair value of derivatives included in our Consolidated Balance Sheets as of December 31, 2012 and December 31, 2011 is summarized below.

	December 31, 2012 (in thousands)	December 31, 2011 (in thousands)
Short-Term Derivative Assets:		
Crude Oil—Collars	$ 90	$ 0
Natural Gas Liquids—Swaps	535	0
Natural Gas—Swaps	2,416	3,912
Natural Gas—Swaption	354	1,047
Natural Gas—Three Way Collars	1,021	1,333
Natural Gas—Collars	4,211	4,112
Natural Gas—Puts	3,378	0
Total Short-Term Derivative Assets	$12,005	$10,404
Long-Term Derivative Assets:		
Crude Oil—Collars	$ 0	$ 143
Natural Gas—Swaps	239	1,377
Natural Gas—Collars	0	5,690
Natural Gas—Three Way Collars	465	861
Natural Gas—Puts	0	505
Total Long-Term Derivative Assets	$ 704	$ 8,576
Total Derivative Assets	$12,709	$18,980
Short-Term Derivative Liabilities:		
Crude Oil—Collars	$ (307)	$ (2,363)
Crude Oil—Swaps	(217)	0
Crude Oil—Three Way Collars	(45)	0
Natural Gas—Three Way Collars	(35)	0
Natural Gas—Swaps	(785)	0
Total Short-Term Derivative Liabilities	$ (1,389)	$ (2,363)
Long-Term Derivative Liabilities:		
Crude Oil—Three Way Collars	$ (509)	$ (632)
Natural Gas—Swaps	(434)	0
Natural Gas—Three Way Collars	(35)	0
Natural Gas—Call	(366)	0
Natural Gas—Collars	(166)	(643)
Total Long-Term Derivative Liabilities	$ (1,510)	$ (1,275)
Total Derivative Liabilities	$ (2,899)	$ (3,638)

Fair value is 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 (exit price). We utilize 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 utilize the best available information. We utilize a fair value hierarchy that 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.

Level 2—Pricing inputs 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.

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.

The following table presents the fair value hierarchy table for assets and liabilities measured at fair value ($ in thousands):

	Fair Value Measurements at December 31, 2012 Using:			
	Total Carrying Value as of December 31, 2012	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Derivatives(a)	$ 9,810	$0	$9,810	$ 0
Asset Retirement Obligations	$24,822	$0	$ 0	$24,822

(a) All of our derivatives are classified as Level 2 measurements. For information regarding their classifications on our Consolidated Balance Sheets, please refer to the previous table.

The value of our oil derivatives are comprised of collar and three way collar contracts for notional barrels of oil at interval New York Mercantile Exchange ("NYMEX") West Texas Intermediate ("WTI") oil prices. The fair value of our oil derivatives as of December 31, 2012 are based on (i) the contracted notional volumes, (ii) independent active NYMEX futures price quotes for WTI oil and (iii) the implied rate of volatility inherent in the contracts. The implied rates of volatility inherent in our contracts were determined based on market-quoted volatility factors. Our gas derivatives are comprised of puts, swaps, swaptions, collars and three way collar contracts for notional volumes of gas contracted at NYMEX Henry Hub ("HH"). The fair values attributable to our gas derivative contracts as of December 31, 2012 are based on (i) the contracted notional volumes, (ii) independent active NYMEX futures price quotes for HH gas, (iii) independent market-quoted forward index prices and (iv) the implied rate of volatility inherent in the contracts. The implied rates of volatility inherent in our contracts were determined based on market-quoted volatility factors. Our natural gas liquids derivatives are comprised of swaps for notional volumes of natural gas liquids contracted at NYMEX Mont Belvieu Propane ("MBP"). The fair values attributable to our natural gas liquids derivative contracts as of December 31, 2012 are based on (i) the contracted notional volumes, (ii) independent active NYMEX futures price quotes for MBP, (iii) independent market-quoted forward index prices and (iv) the implied rate of volatility inherent in the contracts. The implied rates of volatility inherent in our contracts were determined based on market-quoted volatility factors. We classify our derivatives as Level 2 if the inputs used in the valuation models are directly observable for substantially the full term of the instrument; however, if the significant inputs were not observable for substantially the full term of the instrument, we would classify those derivatives as Level 3. We categorize our measurements as Level 2 because the valuation of our derivative instruments are based on similar transactions observable in active markets or industry standard models that primarily rely on market observable inputs. Substantially all of the assumptions for industry standard models are observable in active markets throughout the full term of the instruments.

Asset Retirement Obligations

We report the fair value of asset retirement obligations on a nonrecurring basis in our Consolidated Balance Sheets. We estimate the fair value of asset retirement obligations based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. These inputs are unobservable, and thus result in a Level 3 classification. See Note 2, *Summary of Significant Accounting Policies,* to our Consolidated Financial Statements for further information on asset retirement obligations, which includes a reconciliation of the beginning and ending balances which represent the entirety of our Level 3 fair value measurements.

Financial Instruments Not Recorded at Fair Value

The following table sets forth the fair values of financial instruments that are not recorded at fair value in our Consolidated Financial Statements:

	December 31, 2012		**December 31, 2011**	
In thousands	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
8.875% Senior Notes, Net of Discount	$248,258	$249,074	$ 0	$ 0
Secured Lines of Credit	0	0	225,000	225,000
Capital Leases and Other Obligations	2,677	2,524	544	511
Total	$250,935	$251,598	$225,544	$225,511

The fair value of the secured lines of credit approximates carrying value based on borrowing rates available to us for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy.

The fair value of the capital leases and other obligations are determined using a discounted cash flow approach based on the interest rate and payment terms of the obligations and an assumed discount rate. The fair values of the obligations could be significantly influenced by the discount rate assumptions, which is unobservable. Accordingly, the fair value of the capital leases would be classified as Level 3 in the fair value hierarchy. We measure the fair value of our senior notes using pricing that is readily available in the public market. Accordingly, the fair value of our senior notes would be classified as Level 2 in the fair value hierarchy.

The carrying values of all classes of cash and cash equivalents, accounts receivables and accounts payables are considered to be representative of their respective fair values due to the short term maturities of those instruments.

13. INCOME TAXES

We recognize deferred tax liabilities and assets for the expected future tax consequences of events that may be recognized in our financial statements or tax returns. Using this method, deferred tax liabilities and assets are determined based on the difference between the financial carrying amounts and tax bases of assets and liabilities using enacted tax rates. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Our income tax expense from continuing operations consisted of the following:

	For the Years Ended December 31,		
(in thousands)	**2012**	**2011**	**2010**
Current:			
Federal	$ 2,329	$ 63	$ 11
State	5,825	244	292
Deferred:			
Federal	28,216	8,524	4,741
State	2,179	(561)	456
Income Tax Expense	$38,549	$8,270	$5,500

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

	Year Ended December 31, 2012	Year Ended December 31, 2011	Year Ended December 31, 2010
Income before noncontrolling interests and income taxes	$94,971	$26,358	$13,558
Statutory U.S. income tax rate	35.0%	35.0%	35.0%
Tax expense recognized using statutory U.S. income tax rate	$33,240	$ 9,225	$ 4,745
Change in estimated future state rate	(7)	612	77
Permanent differences	52	176	33
Change in valuation allowance	(131)	1,031	0
Other	(493)	(4,092)	52
Adjusted federal income tax expense	$32,661	$ 6,952	$ 4,907
State income tax expense	5,888	1,318	593
Total income tax expense	$38,549	$ 8,270	$ 5,500
Effective income tax rate	40.6%	31.4%	40.6%

Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes. Deferred tax assets (liabilities) are comprised of the following at December 31, 2012 and 2011:

(in thousands)	For the Years Ended December 31, 2012	2011
Tax effects of temporary differences for:		
Current:		
Assets:		
G&G amortization	$ 0	1,020
Future sale proceeds held in escrow	2,947	0
Non-cash compensation plans	714	0
Valuation allowance	0	(175)
Other	306	329
Total current deferred tax assets	3,967	1,174
Liabilities:		
Unrealized gain on derivatives	(4,365)	(3,315)
Other	(141)	0
Total current deferred tax liabilities	(4,506)	(3,315)
Net total current deferred tax liability	(539)	(2,141)
Long-Term:		
Assets:		
Asset retirement obligation	10,211	7,704
Valuation allowance	(1,732)	(1,688)
Non-cash compensation plans	2,090	2,095
Net operating loss carryforward	4,384	15,714
Organization costs	689	763
Deferred revenue	1,487	0
AMT credits	1,380	74
Other	593	301
Total long-term deferred tax assets	19,102	24,963
Liabilities:		
Unrealized gain on derivatives	0	(3,010)
Timing differences—tax partnerships	(5,873)	(1,818)
Book basis of oil and gas properties in excess of tax basis	(36,805)	(18,434)
Other	(49)	(58)
Total long-term deferred tax liabilities	(42,727)	(23,320)
Net total long-term deferred tax asset (liability)	(23,625)	1,643

Management continuously evaluates the facts and circumstances representing positive and negative evidence in the determination of our ability to realize the deferred tax assets. These deferred tax assets consist primarily of net operating losses and deductible temporary differences. For the year ended December 31, 2012, management determined, based on positive and negative evidence examined and anticipated future taxable income, that it was necessary to provide a valuation allowance of approximately $1.7 million for statutory depletion carryforwards and charitable contributions. Based on the expected patterns of reversal of all existing temporary differences, we have concluded that it is more likely than not that the remaining deferred tax assets will be realized. As of December 31, 2011, we recorded a valuation allowance of approximately $1.9 million for statutory depletion carryforwards and charitable contributions.

Our management will continue, in future periods, to assess the likely realization of the deferred tax assets. The valuation allowance may change based on future changes in circumstances.

At December 31, 2012, we had available unused federal net operating loss carryforwards of $1.7 million that may be applied against future taxable income that expire in 2031. The following table shows expirations by year for federal and state net operating loss carryforwards (all figures presented are tax effected):

Year of Expiration	Net Operating Loss Carryforwards (in thousands)
2020	$ 58
2021	259
2022	64
2023	0
2024	1,091
2025	0
2026	0
2027	0
2028	0
2029	0
2031	2,912
Total	4,384

FASB ASC 740-10 sets forth a two-step process for evaluating tax positions. The first step is financial statement recognition of the tax position based on whether it is more likely than not that the position will be sustained upon examination by taxing authorities and resolution through related appeals or litigation, based on the technical merits of the case. FASB ASC 740-10 mandates certain assumptions in applying the more likely than not judgment, including the presupposition of an examination where the taxing authorities are fully informed of all relevant information for evaluation of the tax position. In other words, FASB ASC 740-10 precludes factoring the likelihood of a tax examination into the evaluation of the outcome so that the evaluation is to focus solely on the technical merits of the position.

Our management has concluded that, as of December 31, 2012, we have not taken any tax positions that would require disclosure as "unrecognized positions" and that no liability balance is required to offset any unsustainable positions. We did not have any accrued interest or penalties as of December 31, 2012 and 2011.

We file a consolidated federal income tax return and separate or consolidated state income tax returns in the United States federal jurisdiction and in many state jurisdictions. We are subject to U.S. federal income tax examinations and to various state tax examinations for periods after August 1, 2007.

14. EARNINGS PER COMMON SHARE

Basic income (loss) per common share is calculated based on the weighted average number of common shares outstanding at the end of the period, excluding restricted stock with performance-based and market-based vesting criteria. Diluted income per common share includes the speculative exercise of stock options and performance-based restricted stock which contain conditions that are not earnings or market-based, given that the hypothetical effect is not anti-dilutive. For the year ended December 31, 2012, we excluded 432,790 stock options from the computation of diluted earnings per share because their effect would have been anti-dilutive. For the year ending December 31, 2011, we excluded 603,064 stock options from the computation of diluted earnings per share because their effect would have been anti-dilutive. Stock options of 715,106 for the year ending December 31, 2010 were outstanding but not included in the computations of diluted net income per share because their effect would be anti-dilutive (for additional information on our non-cash compensation plans, see Note 17, *Employee Benefit and Equity Plans*, to our Consolidated Financial Statements). The following table sets forth the computation of basic and diluted earnings per common share (in thousands except per share data):

	Year Ended December 31, 2012	Year Ended December 31, 2011	Year Ended December 31, 2010
Numerator (in thousands):			
Net Income (Loss) From Continuing Operations	$ 56,422	$ 18,088	$ 8,058
Net Income (Loss) From Discontinued Operations	(10,943)	(33,457)	(2,022)
Net Income (Loss)	$ 45,479	$(15,369)	$ 6,036
Denominator (in thousands):			
Weighted Average Common Shares Outstanding—Basic	51,543	43,930	43,281
Effect of Dilutive Securities:			
Employee Stock Options	69	95	112
Employee Performance-Based Restricted Stock Awards	413	451	277
Weighted Average Common Shares Outstanding—Diluted	52,025	44,476	43,670
Earnings per Common Share(a):			
Basic—Net Income (Loss) From Continuing Operations	$ 1.09	$ 0.41	$ 0.18
—Net Income (Loss) From Discontinued Operations	(0.21)	(0.76)	(0.05)
—Net Income (Loss)	$ 0.88	$ (0.35)	$ 0.13
Diluted—Net Income (Loss) From Continuing Operations	$ 1.08	$ 0.41	$ 0.18
—Net Income (Loss) From Discontinued Operations	(0.21)	(0.76)	(0.05)
—Net Income (Loss)	$ 0.87	$ (0.35)	$ 0.13

(a) All earnings per share amounts are attributable to Rex common shareholders.

15. CAPITAL STOCK

Currently, our common stock is traded on the NASDAQ Global Select Market under the trading symbol "REXX". We have authorized capital stock of 100,000,000 shares of common stock and 100,000 shares of preferred stock. In February 2012, we completed a public offering of 8,050,000 shares of common stock at an offering price of $9.25 per share. The net proceeds from the offering were approximately $70.6 million, after deducting underwriting discounts, commissions and offering expenses. We used a portion of the proceeds to repay outstanding borrowings under our Senior Credit Facility and used the remaining net proceeds to fund a portion of our capital expenditure program for 2012 and for other general corporate purposes. As of December 31, 2012 and 2011, we had 53,213,264 and 44,859,220 shares of common stock outstanding, respectively.

16. MAJOR CUSTOMERS

For the year ended December 31, 2010, approximately $62.0 million, or 92.2%, of our commodity sales from continuing operations were derived from five customers, with the largest customer being responsible for approximately $51.9 million, or 77.2%, of total commodity sales. For the year ended December 31, 2011, approximately $103.6 million, or 92.6%, of our commodity sales from continuing operations were attributable to four customers with the largest single purchaser accounting for $62.9 million, or 56.2%. For the year ended December 31, 2012, approximately $128.3 million, or 95.3% of our commodity sales from continuing operations were attributable to five customers with the largest single purchaser accounting for $64.7 million, or 48.1%.

17. EMPLOYEE BENEFIT AND EQUITY PLANS

401(k) Plan

We sponsor a 401(k) Plan for eligible employees who have satisfied age and service requirements. Employees can make contributions to the plan up to allowable limits. Our contributions to the plan are discretionary. Our contributions to the plan attributable to continuing operations were approximately $0.5 million, $0.4 million and $0.3 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Equity Plans

We recognize all share-based payments to employees, including grants of employee stock options, in our Consolidated Statements of Operations based on their grant-date fair values, using prescribed option-pricing models where applicable. The fair value is expensed over the requisite service period of the individual grantees, which generally equals the vesting period. We report any benefits of income tax deductions in excess of recognized financial accounting compensation as a financing cash flow, rather than as an operating cash flow.

2007 Long-Term Incentive Plan

We have granted stock options, stock appreciation rights and restricted stock awards to various employees, non-employee directors and non-employee contractors under the terms of our 2007 Long-Term Incentive Plan (the "Plan"). The Plan is administered by the Compensation Committee of our board of directors (the "Compensation Committee"). Among the Compensation Committee's responsibilities are selecting participants to receive awards, determining the form, amount and other terms and conditions of awards, interpreting the provisions of the Plan or any award agreement and adopting such rules, forms, instruments and guidelines for administering the Plan as it deems necessary or proper. All actions, interpretations and determinations by the Compensation Committee are final and binding. The composition of the Compensation Committee is intended to permit the awards under the Plan to qualify for exemption under Rule 16b-3 of the Exchange Act. In addition, awards under the Plan, including annual incentive awards paid to executive officers subject to section 162(m) of the Code or covered employees may be designed, at the Compensation Committee's discretion, to satisfy the requirements of section 162(m) to permit the deduction by us of the associated expenses for federal income tax purposes. The Compensation Committee has authorized the issuance of 3,079,470 shares under the Plan, with 813,475 and 929,635 still available as of December 31, 2012 and 2011, respectively.

All awards granted under the Plan have been issued at the prevailing market price at the time of the grant. All outstanding stock options have been awarded with five or ten year expiration at an exercise price equal to our closing price on the NASDAQ Global Market on the day of the award. A forfeiture rate based on a blended average of individual participant terminations and number of awards cancelled is used to estimate forfeitures prospectively.

Stock Options

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

During the year ended December 31, 2012, we did not issue options to purchase shares of our common stock. During the year ended December 31, 2011, the Compensation Committee awarded nonqualified options to purchase a total of 90,074 shares of our common stock to three employees. The nonqualified stock options granted to our employees during 2011 have an exercise price equal to the closing price of our common stock on the NASDAQ Global Select Market on the date of the grant, and vest and become exercisable in one-third increments on the first, second or third anniversary of the grant date, provided that the option holder remains our employee until that date. All options also provide that all unvested options vest and become immediately exercisable upon a "change in control" of us; as that term is defined in the Plan.

A summary of the stock option activity is as follows:

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Aggregate Intrinsic Value (in thousands)
Options outstanding December 31, 2009	873,837	$13.41		
Granted	111,174	11.83		
Exercised	(22,000)	9.99		
Cancelled/Forfeited	(136,500)	18.18		
Options Outstanding December 31, 2010	826,511	$12.50		
Granted	90,074	12.74		
Exercised	(139,682)	9.75		
Cancelled/Forfeited	(78,576)	13.75		
Options Outstanding December 31, 2011	698,327	$12.94		
Granted	0	0		
Exercised	(52,287)	10.80		
Cancelled/Forfeited	(143,787)	20.71		
Options Outstanding December 31, 2012	502,253	$10.95	4.6	$1,406
Options Exercisable December 31, 2012	427,513	$10.64	4.9	$1,374

Stock-based compensation expense from continuing operations relating to stock options for the years ended December 31, 2012, 2011 and 2010 totaled $0.2 million, $0.7 million and $1.0 million, respectively. The expense related to stock option grants was recorded on our Consolidated Statements of Operations under the heading of General and Administrative expense. The intrinsic value of stock options exercised for the years ended December 31, 2012, 2011 and 2010 was $0.1 million, $0.3 million and $0.1 million, respectively. The total tax benefit for the years ended December 31, 2012, 2011 and 2010 was negligible.

The fair value of each option grant is estimated on the date of the grant using the Black-Scholes option-pricing model with the following assumptions:

	For the Years Ended December 31, 2011	2010
Expected Dividend Yield	0%	0%
Expected Stock Price Volatility	74.7%	90.0%
Risk-Free Interest Rate	0.63%	1.66%
Expected Life of Options (Years)	4	4-6.5

The dividend yield of zero is based on the fact that we have never paid cash dividends on common stock and have no present intention of doing so. Our expected historical volatility factor was determined by assessing the common stock trading history of eight publicly-traded oil and gas companies that we determined to be similar to us in ways such as their operating strategy, capital structure, production mix and volume and asset size in addition to our own historical volatility. The risk-free interest rate was determined by interpolating the average yield on a U.S. Treasury bond for a period approximately equal to the expected average life of the options. The average expected life has been determined using the "simplified method" in which the average expected life of the option is equal to the average of the term of the option and the vesting period. We elected to use the simplified method for determining the average expected life because we do not have a history on which to base estimates for the term to exercise of our granted stock options.

Based on the above assumptions, the weighted average estimated fair value of options granted during the years ended December 31, 2011 and 2010 was $6.06 per share and $6.74 per share, respectively. The weighted average exercise price of options granted during 2011 and 2010 was $12.78 and $11.83, respectively.

A summary of the status of our issued and outstanding stock options as of December 31, 2012 is as follows:

	Outstanding			Exercisable	
Exercise Price	Number Outstanding at 12/31/12	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Number Exercisable at 12/31/12	Weighted Average Exercise Price
$5.04	46,041	6.3	$ 5.04	46,041	$ 5.04
$9.50	100,000	4.9	$ 9.50	100,000	$ 9.50
$9.99	196,499	4.8	$ 9.99	196,499	$ 9.99
$10.42	29,548	7.5	$10.42	19,699	$10.42
$11.87	3,500	3.3	$11.87	1,166	$11.87
$12.50	19,139	2.9	$12.50	12,758	$12.50
$13.01	18,526	2.8	$13.01	12,350	$13.01
$13.19	50,000	3.8	$13.19	0	$ 0
$19.92	5,000	0.6	$19.92	5,000	$19.92
$22.34	30,000	5.3	$22.34	30,000	$22.34
$23.28	4,000	0.5	$23.28	4,000	$23.28
Total	502,253	4.6	$10.95	427,513	$10.64

The weighted average remaining contractual term and the aggregate intrinsic value for options outstanding at December 31, 2012 were 4.6 years and $1.4 million, respectively. The weighted average remaining contractual term and the aggregate intrinsic value for options exercisable at December 31, 2011 were 4.7 years and $2.5 million, respectively. As of December 31, 2012, unrecognized compensation expense related to stock options totaled approximately $0.3 million, which will be recognized over a weighted average period of 1.6 years.

Restricted Stock Awards

During the year ended December 31, 2012, the Compensation Committee issued 425,209 shares of restricted common stock to selected employees, non-employee directors and non-employee contractors. During the year ended December 31, 2011, the Compensation Committee issued 709,890 shares of restricted common stock to selected employees, non-employee directors and non-employee contractors. The shares granted in 2012 and 2011 are subject to time vesting and, in some cases, performance-based vesting. The shares will vest on the date on which the Compensation Committee certifies that the performance goals have been satisfied, provided that the recipient has been in continuous employment with us from the grant date until the date upon which the shares are released. Restrictions on the transfer associated with vesting schedules were determined by the Compensation Committee on an individual award basis. The restricted common stock is valued at the closing price of our common stock on the NASDAQ Global Select Market on the date of the grant. Upon a "change in control" of us, as such term is defined in the Plan, all restrictions will immediately lapse for performance-based awards to varying degrees based on performance metrics at the time of the change in control. For awards that do not contain a performance-based condition, all restrictions immediately lapse upon a change in control. Compensation expense associated with the restricted stock award is recognized on a straight-line basis over the vesting period.

Certain of the restricted common stock awards in 2012 are subject to market-based vesting through a calculation of total shareholder return ("TSR") of our common stock relative to a pre-defined peer group of 13 companies over a three-year period. The number of shares ultimately awarded will correspond with the final TSR rank amongst the peer group in accordance with the following schedule:

TSR Rank	Percentage of Awards to Vest
1 – 3	100%
4 – 5	75%
6 – 8	50%
9 – 11	25%
12 – 14	0%

The fair value of the TSR awards of $7.80 per share was estimated on the date of the grant using a Monte Carlo Simulation model that estimates the most likely outcome based on the terms of the award and used the following assumptions:

	Year Ended December 31, 2012
Expected Dividend Yield	0.0%
Risk-Free Interest Rate	0.3%
Expected Volatility—Rex Energy	54.4%
Expected Volatility—Peer Group	31.2%-58.6%
Market Index	37.0%
Expected Life	Three Years

The dividend yield of zero reflects the fact that we have never paid cash dividends on our common stock and have no present intentions of doing so. The risk-free interest rate reflects the U.S. Treasury Constant Maturity rates as of the measurement date, converted into an implied "spot rate" yield. Our expected volatility estimates are based on observed historical volatility of daily stock returns for the three-year period preceding the grant date. Market index is an equal-weight index of the companies in the peer group. Expected life is measured as the grant date through the end of the performance period. Performance and market shares will vest on the date on which the Compensation Committee certifies that the performance goals have been satisfied, provided that the recipient has been in continuous employment with us from the grant date through the third anniversary of the grant date. Compensation expense for the TSR awards is recognized on a straight-line basis over the vesting period.

We recorded compensation expense related to restricted common stock awards of $2.9 million, $0.9 million and $0.1 million for the years ended December 31, 2012, 2011 and 2010, respectively. As of December 31, 2012, total unrecognized compensation cost related to the restricted common stock grants was approximately $4.3 million to be recognized over a weighted average of 2.1 years. The total fair value of restricted common stock awards that vested in 2012 was approximately $0.7 million. There were no restricted stock vestings prior to 2012.

A summary of the restricted stock activity for the years ended December 31, 2012, 2011 and 2010 is as follows:

	Number of Shares	Weighted-Average Grant Date Fair Value
Restricted stock awards, as of January 1, 2010	248,100	$ 3.74
Awards	860,563	12.07
Forfeitures	(293,698)	7.99
Restricted stock awards, as of December 31, 2010	814,965	$11.01
Awards	757,816	13.07
Forfeitures	(342,955)	11.60
Restricted stock awards, as of December 31, 2011	1,229,826	$12.11
Awards	425,209	11.59
Vested	(70,750)	2.05
Forfeitures	(152,712)	12.13
Restricted stock awards, as of December 31, 2012	1,431,573	$12.45

18. IMPAIRMENT EXPENSE

For the years ended December 31, 2012, 2011 and 2010, we incurred impairment expense from continuing operations of approximately $20.6 million, $14.6 million and $8.9 million, respectively. We continually monitor the carrying value of our oil and gas properties and make evaluations of their recoverability when circumstances arise that may contribute to impairment (for additional information see Note 2, *Summary of Significant Accounting Policies*, to our Consolidated Financial Statements). During 2012, we incurred approximately $13.7 million of expense related to the impairment of proved unconventional natural gas wells in the Appalachian Basin, which in part was driven by the continued low natural gas pricing environment. All of the proved unconventional natural gas wells that were impaired produce dry natural gas and are located in both our operated and non-operated areas in the Appalachian Basin. In addition to the impairment related to our natural gas properties, we incurred approximately $5.8 million in impairment expense primarily related to the expected future expiration or surrender of undeveloped acreage in our non-operated dry gas area of Clearfield County, Pennsylvania. The remaining impairment was due to three non-operated properties in the Illinois Basin. During 2011, we incurred approximately $11.6 million of expense related to the impairment of proved conventional shallow natural gas wells in the Appalachian Basin. In addition to the impairment related to our conventional shallow natural gas properties, we incurred approximately $1.4 million in impairment expense related to the expiration or surrender of undeveloped acreage and $1.6 million in impairment expense related to a refrigeration plant in the Appalachian Basin which was formerly in use before the commencement of operations at the cryogenic gas processing plants in Butler County, Pennsylvania. With larger scale gas processing capabilities in the region there is no further value for the refrigeration plant. During 2010, we determined that the carrying values of two of our test wells in Clearfield County, Pennsylvania, which were in various stages of drilling and completion, and did not hold proved reserves, were not recoverable due to a lack of a sales outlet and no current plans by us to complete the wells for commercial production. The carrying value of these wells before impairment was approximately $3.9 million. In addition, we incurred approximately $2.3 million in impairment expense related to the expiration or surrender of undeveloped acreage.

19. SUSPENDED EXPLORATORY WELL COSTS

We capitalize the costs of exploratory wells if a well finds a sufficient quantity of reserves to justify its completion as a producing well and we are making sufficient progress towards assessing the reserves and the economic and operating viability of the project.

The following table reflects the net change in capitalized exploratory well costs, excluding those related to Assets Held for Sale on our Consolidated Balance Sheets for the years ended December 31, 2012, 2011 and 2010 ($ in thousands):

	2012	2011	2010
Beginning Balance at January 1,	$ 11,756	$ 1,637	$ 5,107
Additions to capitalized exploratory well costs pending the determination of estimated proved reserves	95,980	106,045	34,330
Divested wells	0	0	(10,770)
Reclassification of wells, facilities, and equipment based on the determination of estimated proved reserves	(70,518)	(95,926)	(23,016)
Capitalized exploratory well costs charged to expense	(250)	0	(4,014)
Ending Balance at December 31,	36,968	11,756	1,637
Less exploratory well costs that have been capitalized for a period of one year or less	(36,630)	(11,756)	(1,637)
Capitalized exploratory well costs for a period of greater than one year	$ 338	$ 0	$ 0
Number of projects that have exploratory well costs capitalized for a period of more than one year	2	0	0

As of December 31, 2012 we had approximately $0.3 million in capitalized exploratory well costs that were capitalized for a period greater than one year. These costs are related to two wells in our operated region in Butler County, Pennsylvania in the Appalachian Basin. These costs represent preliminary permitting and engineering expenses that we typically incur several months in advance of commencing drilling operations. Both wells are scheduled for completion activity in 2013, at which time they will be reclassified to Evaluated Oil and Gas Properties upon the discovery of proved reserves or to Exploration Expense if commercial quantities of reserves are not found.

20. COSTS INCURRED IN OIL AND NATURAL GAS ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES (UNAUDITED)

Costs incurred in oil and natural gas property acquisitions and development are presented below and exclude any costs incurred related to Assets Held for Sale (in thousands):

	2012	2011	2010
Consolidated Entities:			
Acquisition of Properties			
Proved	$ 1,474	$ 9	$ 53
Unproved	49,331	76,852	43,166
Exploration Costs	128,748	113,075	36,008
Development Costs(a)	57,149	61,920	24,825
Subtotal	236,702	251,856	104,052
Asset Retirement Obligations	4,480	316	186
Total Costs Incurred	$241,182	$252,172	$104,238
Share of Equity Method Investments:			
Acquisition of Properties			
Proved	$ 0	$ 0	$ 0
Unproved	0	0	0
Exploration Costs	0	0	0
Development Costs(a)	4,316	12,682	6,018
Total	$ 4,316	$ 12,682	$ 6,018

(a) Includes Depreciation expense for support equipment and facilities.

The following table provides a reconciliation of the total costs incurred for our consolidated entities to our reported capital expenditures (in thousands):

	2012	2011	2010
Total Costs Incurred by Consolidated Entities	$241,182	$252,172	$104,238
Equity Method Investments	4,087	23,204	8,721
DJ Basin Expenditures	3,146	24,029	45,659
Exploration Expense	(4,782)	(2,507)	(2,578)
Asset Retirement Obligations	(4,480)	(316)	(186)
Depreciation for Support Equipment and Facilities	(4,187)	(3,308)	(2,948)
Other	3,888	9,142	11,634
Total Capital Expenditures	$238,854	$302,416	$164,540

21. OIL AND NATURAL GAS CAPITALIZED COSTS (UNAUDITED)

Our aggregate capitalized costs for natural gas and oil production activities with applicable accumulated depreciation, depletion and amortization are presented below and exclude any properties classified as Assets Held for Sale (in thousands):

	2012	2011
Consolidated Entities:		
Proven Oil and Natural Gas Properties	$ 485,448	$ 349,938
Pipelines and Support Equipment	31,231	30,926
Field Operation Vehicles and Other Equipment	13,412	9,489
Wells and Facilities in Progress	91,685	61,355
Unproven Properties	161,618	123,241
Total	783,394	574,949
Less Accumulated Depreciation and Depletion	(141,769)	(104,894)
Total	$ 641,625	$ 470,055
Share of Equity Method Investments:		
Pipelines and Support Equipment	$ 17,524	$ 25,344
Field Operation Vehicles and Other Equipment	0	36
Wells and Facilities in Progress	26	16,637
Total	17,550	42,017
Less Accumulated Depreciation and Depletion	(1,077)	(1,817)
Total	$ 16,473	$ 40,200

22. OIL AND NATURAL GAS RESERVE QUANTITIES (UNAUDITED)

Our independent engineers, Netherland, Sewell, and Associates, Inc. ("NSAI") evaluated all of our proved oil, natural gas and NGL reserves for the years ended December 31, 2012, 2011 and 2010. The technical persons responsible for preparing the estimates of our estimated proved reserves meet the requirements with regards 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. Our independent third-party engineers do not own an interest in any of our properties and are not employed by us on a contingent basis. We emphasize that reserve estimates are inherently imprecise. Our oil, natural gas and NGL reserve estimates were generally based upon extrapolation of historical production trends, analogy to similar properties and volumetric calculations. Accordingly, these estimates are expected to change, and such change could be material and occur in the near term as future information becomes available. All of our estimated proved reserves are located within the United States.

Proved oil, natural gas and NGL reserves represent the estimated quantities of oil, natural gas and NGLs which geoscience and engineering data demonstrate with reasonable certainty will be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and governmental 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. Proved developed oil, natural gas and NGL reserves are those expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes 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. Estimated 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 formation. Proved undeveloped reserves can only be assigned to acreage for which improved recovery technology is contemplated unless such techniques have been proven effective by actual tests in the area and in the same reservoir. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating they are scheduled to be drilled within five years, unless specific circumstances justify a longer time. We have approximately two gross (1.1 net) PUD locations that are to be developed more than five years after first booking. These wells are a part of a development program which includes multiple wells from the same pad that has been pushed outside of the five year range due to our current strategy of drilling single well pads to hold acreage. We believe that this strategy allows for the wells to remain classified as PUD locations. A total of 6.3 Bcfe of estimate proved reserves are attributed to these wells.

Presented below is a summary of changes in estimated reserves of the oil and natural gas wells at December 31, 2012, 2011 and 2010.

	2012		
	Oil and NGLs (Bbls)	**Natural Gas (Mcf)**	**Mcf Equivalents**
Estimated Proved Reserves—Beginning of Period	15,316,001	274,292,315	366,188,321
Extensions, Discoveries and Additions	13,288,024	116,854,386	196,582,530
Revisions	12,740,217	(1,413,637)	75,027,665
Improved Recovery	758,303	0	4,549,818
Purchases	43,176	0	259,056
Production	(1,090,115)	(18,016,700)	(24,557,390)
Estimated Proved Reserves—End of Period	41,055,606	371,716,364	618,050,000

	2011		
	Oil and NGLs (Bbls)	**Natural Gas (Mcf)**	**Mcf Equivalents**
Estimated Proved Reserves—Beginning of Period	12,342,828	127,621,835	201,678,803
Extensions, Discoveries and Additions	2,796,834	139,067,694	155,848,698
Revisions(a)	1,060,941	16,515,036	22,880,682
Production(b)	(884,602)	(8,912,250)	(14,219,862)
Estimated Proved Reserves—End of Period	15,316,001	274,292,315	366,188,321

	2010		
	Oil and NGLs (Bbls)	Natural Gas (Mcf)	Mcf Equivalents
Estimated Proved Reserves—Beginning of Period	11,509,983	56,163,170	125,223,068
Sale of Reserves in Place	(369,758)	(12,251,612)	(14,470,160)
Extensions, Discoveries and Additions	3,461,768	93,229,532	114,000,140
Revisions	(1,542,033)	(6,511,733)	(15,763,931)
Production(b)	(717,132)	(3,007,522)	(7,310,314)
Estimated Proved Reserves—End of Period	12,342,828	127,621,835	201,678,803

(a) Revisions includes 120.9 MBbls and 725.4 MMcfe related to our successful ASP pilot in the Illinois Basin.

(b) Gas production excludes certain production associated with gas sales contracts for which we do not recognize reserves.

	Oil and NGLs (Bbls)	Natural Gas (Mcf)	Mcf Equivalent
Proved Developed Reserves			
December 31, 2012	19,359,788	141,754,981	257,913,709
December 31, 2011	10,399,620	110,853,300	173,251,020
December 31, 2010	8,799,105	32,477,226	85,271,856

Revisions. Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from developmental drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs.

We had significant revisions in our oil, NGL and natural gas reserves for the year ended December 31, 2012. Revisions due to price in our natural gas operations resulted in a significant loss of reserves. Prices used for natural gas reserves decreased from $4.55 in 2011 to $2.94 in 2012. Partially offsetting the decrease due to pricing were increased reserves due to additional field production data demonstrating better well performance than as of year-end 2011. We believe this increased performance is the result of improved completion techniques. During 2012, we executed an agreement to sell ethane as a separate product in our NGL stream, which is currently being utilized as plant fuel. As such, we booked for the first time ethane barrels as part of our NGL reserves. The ethane reserves contained within revisions to previous estimates are barrels associated to those wells which were considered to be proved locations as of December 31, 2011. We also had revisions in our non-operated properties. In our Westmoreland Marcellus, we saw reserve increases as a result of field production data demonstrating better well performance than last year's estimates. For our Clearfield County Marcellus proved undeveloped acreage, we saw a reduction in proved reserves primarily due to offset well performance. In our Illinois Basin asset, we saw positive revisions, with a significant portion being the result of our re-frac program of stacked pay intervals instituted during the middle of 2012. We had significant revisions in our oil, NGL and natural gas reserves for the year ended December 31, 2011. The majority of our positive revision of estimated proved reserves occurred in our Marcellus Shale properties, where our average per well estimated ultimate recovery ("EUR") increased from 4.4 Bcfe to 5.3 Bcfe in our operated areas and from 3.0 Bcf to 4.2 Bcf in our non-operated Marcellus areas. These increases were due to additional field production data demonstrating better well performance compared to prior year performance. We believe that the increased performance was primarily the result of improved completion techniques. In total, the positive revisions in our Marcellus operations accounted for 84% of all revisions. Also impacting our revisions during 2011 was a change in the oil pricing from $76.03 per barrel in 2010 to $92.45 per barrel in 2011. We had significant revisions in our oil and NGL reserves of approximately 1.5 MMBOE for the year ended December 31, 2010, which were primarily due to a decrease in the pricing used for our NGLs from $57.65 per barrel in 2009 to $31.71 per barrel in 2010.

Extensions, discoveries and other additions. These are additions to estimated proved reserves that result from (1) extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with estimated proved reserves or of new reservoirs of estimated proved reserves in old fields.

We had significant extensions, discoveries and other additions for the year ended December 31, 2012, of 13.3 MMBOE of oil and NGLs and 116.9 Bcf of natural gas. These additions were primarily due to the additional proved undeveloped locations that were added to our proved reserve estimates that were a result of our continued drilling success in the Marcellus Shale. A portion of the extension and discoveries were booked as a result of successful efforts from exploration wells drilled in the Utica Shale and the development of stacked reservoirs through the drilling of previously undeveloped acreage in the Illinois Basin. We had significant extensions, discoveries and other additions for the year ended December 31, 2011, of 2.8 MMBOE of oil and NGLs and 139.1 Bcf of natural gas. These additions were primarily due to the additional proved undeveloped locations that were added to our proved reserve estimates that were a result of our continued drilling success in the Marcellus Shale. A portion of the extension and discoveries were booked as a result of successful efforts from exploration wells drilled in the Burkett and Utica Shales. In the Illinois Basin, we successfully booked estimated proved reserves as a result of our ASP pilot, which were classified as revisions. For the year ended December 31, 2010 we had significant extensions, discoveries of 3.5 MMBOE for oil and NGLs and 93.2 Bcfe for natural gas. These additions were primarily due to the additional proved undeveloped locations that were added to our proved reserve estimates that were a result of our continued drilling success in the Marcellus Shale. Extensions, discoveries and other additions for the year ended December 31, 2009 of 0.9 MMBOE of oil and NGLs and 18.4 Bcfe of natural gas include increases in proved undeveloped locations as a result of our successful exploration efforts in the Marcellus Shale in conjunction with the change in the SEC's rules to allow producers in continuous accumulation plays to report additional undrilled locations beyond one offset on each side of a horizontal producing well.

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

FASB ASC 932 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to the estimated proved reserves. We followed these guidelines, which are briefly discussed below.

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

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

The following summary sets forth our future net cash flows relating to proved oil and natural gas reserves based on the standardized measure prescribed by FASB ASC 932 at December 31, 2012, 2011 and 2010 ($ in thousands):

	2012	2011	2010
Future Cash Inflows	$ 2,988,231(a)	$2,333,513(b)	$1,335,068(c)
Future Costs:			
Production	(1,387,653)	(880,077)	(542,814)
Abandonment	(85,859)	(65,560)	(63,637)
Development	(324,873)	(251,821)	(152,965)
Net Future Cash Inflow Before Income Taxes	1,189,846	1,136,055	575,652
Future Income Tax Expense	(245,078)	(277,568)	(139,482)
Total Future Net Cash Flows Before 10.0% Discount	944,768	858,487	436,170
Less: Effect of a 10.0% Discount Factor	(548,645)	(444,552)	(248,105)
Standardized Measure of Discounted Future Net Cash Flows	$ 396,123	$ 413,935	$ 188,065

(a) Calculated using weighted average prices of $2.94 per Mcf, $90.92 per barrel of oil and $32.91 per barrel of NGLs
(b) Calculated using weighted average prices of $4.55 per Mcf, $92.45 per barrel of oil and $46.34 per barrel of NGLs
(c) Calculated using weighted average prices of $4.57 per Mcf, $76.03 per barrel of oil and $31.71 per barrel of NGLs

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

	2012	2011	2010
Standardized Measure—Beginning of Period	$ 413,935	$188,065	$144,379
Revisions of Previous Estimates:			
Changes in Prices and Production Costs	(198,433)	29,223	33,083
Revisions in Quantities	91,462	40,525	(36,541)
Changes in Future Development Costs	(3,885)	(19,539)	(46,082)
Accretion of Discount and Timing of Future Cash Flows	52,093	25,218	17,438
Net Change in Income Tax	27,405	(42,875)	(34,117)
Purchase (Sale) of Reserves in Place	1,188	0	(10,438)
Plus Extensions, Discoveries, and Other Additions	88,749	159,047	44,135
Development Costs Incurred	57,149	61,290	24,825
Sales of Product—Net of Production Costs	(86,936)	(78,763)	(42,568)
Changes in Timing and Other	(46,604)	51,744	93,951
Standardized Measure—End of Period	$ 396,123	$413,935	$188,065

24. RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

Results of operations are equal to revenues, less (a) production costs, (b) impairment expenses, (c) exploration expenses, (d) DD&A expenses, and (e) income tax expense (benefit) (certain prior year amounts have been reclassified to conform to current presentation):

	2012	2011	2010
Consolidated Entities (in thousands):			
Revenues			
Oil and Natural Gas Sales	$134,574	$111,879	$67,224
Expenses			
Production and Lease Operating Expense	47,638	33,116	24,656
Impairment Expense	20,505	14,316	8,424
Exploration Expense	4,782	2,507	2,578
Depletion, Depreciation, Amortization and Accretion	44,955	27,670	21,422
Total Costs	117,880	77,609	57,080
Pre-Tax Operating Income (Loss)	16,694	34,270	10,144
Income Tax Expense(a)	6,778	10,760	4,118
Results of Operations for Oil and Gas Producing Activities	$ 9,916	$ 23,510	$ 6,026
Share of Equity Method Investments (in thousands):			
Expenses			
Depletion, Depreciation, Amortization and Accretion	$ 1,082	$ 1,568	$ 181
Total Costs	1,082	1,568	181
Pre-Tax Operating Loss	(1,082)	(1,568)	(181)
Income Tax Benefit(a)	435	519	75
Results of Operations for Oil and Gas Producing Activities	$ (647)	$ (1,049)	$ (106)
Total Consolidated and Equity Method Investees Results of Operations for Oil and Gas Producing Activities	$ 9,269	$ 22,461	$ 5,920

(a) Computed using the effective rate for continuing operations for each period: 40.6% in 2012; 31.4% in 2011 and; 40.6% in 2010.

25. LITIGATION

Illinois Basin EPA Consent Decree

In September 2006, the United States Department of Justice ("DOJ"), the United States Environmental Protection Agency ("EPA") and the State of Illinois initiated an enforcement action against us seeking mandatory injunctive relief and potential civil penalties based on allegations that we (and various predecessor companies) were violating the Clean Air Act in connection with the release of hydrogen sulfide gas and volatile organic compounds ("VOC's") in the course of our oil producing operations near the towns of Bridgeport, Illinois and Petrolia, Illinois. In June 2007, we entered a consent decree to resolve the enforcement. The consent decree required us to take certain remedial actions to reduce hydrogen sulfide and VOC emissions and monitor the same. The consent decree did not require us to pay any civil fine or penalty, although it does provide for the possible imposition of specified daily fines and penalties for any violation of the terms and conditions of the consent decree.

In January 2010, we submitted certain proposed revisions to a Directed Inspection and Maintenance Plan previously implemented by us pursuant to the terms of the consent decree. In general, the proposed revisions update the plan to reflect changes in hydrogen sulfide control measures and procedures implemented in the field and changes in procedures for responding to resident complaints of hydrogen sulfide odors. The EPA, DOJ and Illinois EPA all approved these revisions.

Settlement Agreement—Illinois Class Action Litigation

We were a defendant in a class action lawsuit filed in the United States District Court for the Southern District of Illinois. This action was commenced in October 2006 by plaintiffs Julia Leib and Lisa Thompson, individually and as putative class representatives on behalf of all persons and non-governmental entities that own property or reside on property located in the towns of Bridgeport and Petrolia, Illinois. The complaint asserted several causes of action, including violation of the Resource Conservation and Recovery Act, Illinois Environmental Protection Act, negligence, private nuisance, trespass, and willful and wanton misconduct.

In December 2009, we entered into a Settlement Agreement and Release (the "Settlement Agreement") with Leib and Thompson, individually and on behalf of a certified class, to settle the class action lawsuit. Under the terms of the Settlement Agreement, without any admission of liability, we agreed to pay the class a total of $1.9 million. Pursuant to the terms of a pollution liability policy, $1.0 million of the settlement payment was funded by our insurance carrier. Pursuant to the Settlement Agreement, we also agreed to permanently plug four inactive oil wells. In return for the above consideration, each member of the class released all claims against us that in any way related to hydrogen sulfide or other environmental conditions in the class area that were the subject of, or could have been the subject of, the claims alleged in the class action lawsuit. In addition, each class member released any claims related to any future releases of hydrogen sulfide in the class area on the condition that we substantially comply with the terms and conditions of the consent decree describe above in " *Illinois Basin EPA Consent Decree* " . The Settlement Agreement did not provide for a release of any potential individual claims of other class members since those claims were not the subject of the class action lawsuit. The Settlement Agreement became effective in April 2010.

Litigation Related to Proposed Oil and Gas Leases in Westmoreland and Clearfield Counties, Pennsylvania

In July 2009, we were named as defendants in a proposed class action lawsuit filed in the Court of Common Pleas of Westmoreland County, Pennsylvania (the "Snyder Case"). The named plaintiffs were five individuals who sued on behalf of themselves and all persons who are alleged to be similarly situated. The complaint in the Snyder Case generally asserted that a binding contract to lease oil and gas property was formed between the Company and each proposed class member when representatives of Duncan Land & Energy, Inc. ("Duncan Land"), a leasing agent that we engaged, presented a form of proposed oil and gas lease to each person, and each person signed the proposed oil and gas lease form and delivered the executed proposed lease to representatives of Duncan Land. We rejected these leases and never signed them. The plaintiffs sought a judgment declaring the rights of the parties with respect to those proposed leases, as well as damages and other relief, together with interest, costs, expenses and attorneys' fees.

In May 2011, we entered into a Settlement Agreement with respect to these legal proceedings. In July 2011, the court approved the Settlement Agreement, pursuant to which we offered each eligible class member an oil and gas lease, in a form agreed to by the parties, with a prepaid rental of $2,500 per acre for a five-year term with a 15% royalty. We also agreed to pay $30,000 to plaintiffs' attorneys for the anticipated expenses of administration of the Settlement Agreement. Additionally, we deposited $2.5 million into a fund for distribution to class members and for attorney's fees, costs and expenses of counsel for the class. The final order regarding the Settlement Agreement dismissed all claims against us with prejudice and without any admission of liability, and provided a release by all class members of all claims against us in connection with the litigation.

In June 2009, we were also named as a defendant in a lawsuit filed in the Court of Common Pleas of Clearfield County, Pennsylvania (the "Liegey Case"). The Liegey Case was brought by eight individuals involving oil and gas leasing activity in Clearfield County, Pennsylvania. The complaint in the Liegey Case asserted similar claims and requests for relief as those made in the Snyder Case described above. In June 2010, we settled the case and in July 2010, the court dismissed the case.

Litigation Related to Proposed Oil and Gas Leases in Clearfield County, Pennsylvania

In October 2011, we were named as defendants in a proposed class action lawsuit filed in the Court of Common Pleas of Clearfield County, Pennsylvania (the "Cardinale Case"). The named plaintiffs are two individuals who have sued on behalf of themselves and all persons who are alleged to be similarly situated. The complaint in the Cardinale Case generally asserts that a binding contract to lease oil and gas interests was formed between the Company and each proposed class member when representatives of Western Land Services, Inc. ("Western"), a leasing agent that we engaged, presented a form of proposed oil and gas lease and an order for payment to each person in 2008, and each person signed the proposed oil and gas lease form and order for payment and delivered the documents to representatives of Western. We rejected these leases and never signed them. The plaintiffs seek a judgment declaring the rights of the parties with respect to those proposed leases, as well as damages and other relief as may be established by plaintiffs at trial, together with interest, costs, expenses and attorneys' fees.

We filed affirmative defenses and preliminary objections to the plaintiff's claims, and the parties each made various responsive filings throughout the first quarter of 2012. In May 2012, the trial court dismissed the Cardinale case with prejudice on the grounds that there was no contract formed between us and the plaintiffs. The plaintiffs appealed the dismissal and the parties filed briefs and responses during the second half of 2012. The appeal was argued by the parties in February 2013; however, as of the date of this report, there has been no ruling on the appeal.

In July 2012, counsel for the plaintiffs in the Cardinale case filed two additional lawsuits against us in the Court of Common Pleas of Clearfield County, Pennsylvania: one a proposed class action lawsuit with a different named plaintiff (the "Billotte case") and another on behalf of a group of individually named plaintiffs (the "Meeker case"). The complaint for the Billotte case contains the same claims as those set forth in the Cardinale case. We have not yet been served with a complaint in the Meeker case, but we believe the claims will also mirror those made in the Cardinale and Billotte cases. It is our understanding that these two additional lawsuits were filed for procedural reasons in light of the dismissal of the Cardinale case. Proceedings in both the Billotte and Meeker cases have been stayed pending the outcome of the appeal in the Cardinale case.

We intend to vigorously defend against each of these claims. Due to the dismissal of the Cardinale case and the uncertainty of the outcome of the appeal, and the similarity of the claims for the Billotte and Meeker cases, we are unable to express an opinion with respect to the likelihood of an unfavorable outcome for any of these cases or provide an estimate of potential losses.

26. SUBSEQUENT EVENTS

DJ Basin Assets

In 2013, we entered an agreement to sell our remaining DJ Basin assets for $3.1 million, subject to customary due diligence and title research. As of December 31, 2012, these assets were recorded on our Consolidated Balance Sheet at a carrying value of $2.3 million.

27. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

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

REX ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS
($ and Shares in Thousands Except per Share Data)

	2012			
	March	June	September	December
Revenues	$33,834	$ 30,257	$38,929	$45,119
Costs and Expenses	30,006	(25,936)	40,671	46,157
Net Income (Loss) From Continuing Operations	3,828	56,193	(1,742)	(1,038)
Net Loss From Discontinued Operations	(5,355)	(3,050)	(258)	(2,280)
Net Income (Loss)	(1,527)	53,143	(2,000)	(3,318)
Net Income Attributable to Noncontrolling Interests	101	222	193	303
Net Income (Loss) Attributable to Rex Energy	$ (1,628)	$ 52,921	$ (2,193)	$ (3,621)
Income (Loss) per Common Share Attributable to Rex Common Shareholders:				
Basic—Continuing Operations Attributable to Rex Energy	$ 0.08	$ 1.08	$ (0.04)	$ (0.03)
Basic—Discontinued Operations	(0.11)	(0.06)	0.00	(0.04)
Basic—Net Income (Loss)	$ (0.03)	$ 1.02	$ (0.04)	$ (0.07)
Basic—Weighted Average Shares Outstanding	48,744	52,009	52,036	52,278
Diluted—Continuing Operations Attributable to Rex Energy	$ 0.08	$ 1.06	$ (0.04)	$ (0.03)
Diluted—Discontinued Operations	(0.11)	(0.06)	0.00	(0.04)
Diluted—Net Income (Loss)	$ (0.03)	$ 1.00	$ (0.04)	$ (0.07)
Diluted—Weighted Average Shares Outstanding	49,693	52,876	52,036	52,278

	2011			
	March	June	September	December
Revenues	$23,147	$29,023	$ 30,755	$31,681
Costs and Expenses	26,680	21,226	18,089	30,532
Net Income (Loss) From Continuing Operations	(3,533)	7,797	12,666	1,149
Net Loss From Discontinued Operations	(4,069)	(4,313)	(20,812)	(4,263)
Net Income (Loss)	(7,602)	3,484	(8,146)	(3,114)
Net Income (Loss) Attributable to Noncontrolling Interests	(102)	44	44	7
Net Income (Loss) Attributable to Rex Energy	$ (7,500)	$ 3,440	$ (8,190)	$ (3,121)
Income (Loss) per Common Share Attributable to Rex Common Shareholders:				
Basic—Continuing Operations Attributable to Rex Energy	$ (0.08)	$ 0.18	$ 0.29	$ 0.03
Basic—Discontinued Operations	(0.09)	(0.10)	(0.47)	(0.10)
Basic—Net Income (Loss)	$ (0.17)	$ 0.08	$ (0.18)	$ (0.07)
Basic—Weighted Average Shares Outstanding	43,862	43,880	43,951	44,026
Diluted—Continuing Operations Attributable to Rex Energy	$ (0.08)	$ 0.18	$ 0.29	$ 0.03
Diluted—Discontinued Operations	(0.09)	(0.10)	(0.47)	(0.10)
Diluted—Net Income (Loss)	$ (0.17)	$ 0.08	$ (0.18)	$ (0.07)
Diluted—Weighted Average Shares Outstanding	43,862	44,451	44,384	44,567

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

Not applicable.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. We have established disclosure controls and procedures to ensure that material information relating to the company is made known to the officers who certify the financial statements and to other members of senior management and the audit committee of our board of directors. As of December 31, 2012, an evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer (the "CEO") and the Chief Financial Officer (the "CFO"), of the effectiveness of the design and operation of the our disclosure controls and procedures (as defined in Rules 13a-15(e), and 15d-15(e) under the Securities Exchange Act of 1934). An evaluation was conducted to ensure that information we are required to disclose in reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms. Our CEO and CFO have concluded that our disclosure controls and procedures were effective as of the date of such evaluation.

Changes in Internal Control over Financial Reporting. No change to our internal control over financial reporting occurred during the year ended December 31, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control 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) under the Securities Exchange Act of 1934). Management has used the framework set forth in the report entitled *Internal Control—Integrated Framework* published by the COSO of the Treadway Commission to evaluate the effectiveness of our internal control over financial reporting. Internal control over financial reporting refers to the process designed by, or under the supervision of, our CEO and CFO, and overseen by our board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, and includes those policies and procedures that:

- Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with general 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
- 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.

Our 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, however, neither internal control over financial reporting nor disclosure controls and procedures can provide absolute assurance of achieving financial reporting objectives because of their inherent limitations. Internal control over financial reporting and disclosure controls are processes that involve human diligence and compliance, and are subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting and disclosure controls also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented, detected or reported on a timely basis by internal control over financial reporting or disclosure controls. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design safeguards for these processes that will reduce, although may not eliminate, these risks.

Management has concluded that our internal controls over financial reporting and our disclosure controls and procedures were effective as of December 31, 2012. Management reviewed the results of their assessment with our Audit Committee. The effectiveness of our internal control over financial reporting as of December 31, 2012 has been audited by KPMG, LLP an independent registered public accounting firm, as stated in their report which is set forth below.

Report of Independent Registered Public Accounting Firm

The Board of Directors
Rex Energy Corporation:

We have audited Rex Energy Corporation and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Rex Energy Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, 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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with 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 (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Rex Energy Corporation and subsidiaries as of December 31, 2012 and 2011, and the related consolidated statements of operations, changes in noncontrolling interests and stockholders' equity (deficit), and cash flows for the years then ended, and our report dated March 14, 2013 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP
Dallas, Texas
March 14, 2013

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is incorporated by reference to such information as set forth in our definitive Proxy Statement (the "2013 Proxy Statement") for our 2013 annual meeting of stockholders. The 2013 Proxy statement will be filed with the SEC not later than 120 days subsequent to December 31, 2012.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is incorporated herein by reference to the 2013 Proxy Statement for the 2013 annual meeting of stockholders, which will be filed with the SEC not later than 120 days subsequent to December 31, 2012.

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

The information required by this item is incorporated herein by reference to the 2013 Proxy Statement for the 2013 annual meeting of stockholders, which will be filed with the SEC not later than 120 days subsequent to December 31, 2012.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated herein by reference to the 2013 Proxy Statement for the 2013 annual meeting of stockholders, which will be filed with the SEC not later than 120 days subsequent to December 31, 2012.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is incorporated herein by reference to the 2013 Proxy Statement for the 2013 annual meeting of stockholders, which will be filed with the SEC not later than 120 days subsequent to December 31, 2012.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

(a)(1) Financial Statements

(a)(2) Financial Statement Schedules

All other schedules are omitted because they are not applicable, not required, or because the required information is included in the financial statements or related notes.

(a)(3) Exhibits.

Exhibit Number	Exhibit Title
2.1	Participation and Exploration Agreement, dated August 31, 2010, by and among Summit Discovery Resources II, LLC, Rex Energy I, LLC, R.E. Gas Development, LLC, joined therein by Rex Energy Operating Corp., and for the limited purposes set forth therein, Rex Energy Corporation and Sumitomo Corporation (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K filed with the SEC on September 3, 2010).
2.2	Form of Area One Tax Partnership Agreement attached and made a part of the Participation and Exploration Agreement, dated August 31, 2010, by and among Summit Discovery Resources II, LLC, Rex Energy I, LLC, R.E. Gas Development, LLC, joined therein by Rex Energy Operating Corp., and for the limited purposes set forth therein, Rex Energy Corporation and Sumitomo Corporation (incorporated by reference to Exhibit 2.2 to our Current Report on Form 8-K filed with the SEC on September 3, 2010).
2.3	Form of Area Two Tax Partnership Agreement attached and made a part of the Participation and Exploration Agreement, dated August 31, 2010, by and among Summit Discovery Resources II, LLC, Rex Energy I, LLC, R.E. Gas Development, LLC, joined therein by Rex Energy Operating Corp., and for the limited purposes set forth therein, Rex Energy Corporation and Sumitomo Corporation (incorporated by reference to Exhibit 2.3 to our Current Report on Form 8-K filed with the SEC on September 3, 2010).
2.4	Form of Area Three Tax Partnership Agreement attached and made a part of the Participation and Exploration Agreement, dated August 31, 2010, by and among Summit Discovery Resources II, LLC, Rex Energy I, LLC, R.E. Gas Development, LLC, joined therein by Rex Energy Operating Corp., and for the limited purposes set forth therein, Rex Energy Corporation and Sumitomo Corporation (incorporated by reference to Exhibit 2.4 to our Current Report on Form 8-K filed with the SEC on September 3, 2010).
2.5	Form of Area Four Tax Partnership Agreement attached and made a part of the Participation and Exploration Agreement, dated August 31, 2010, by and among Summit Discovery Resources II, LLC, Rex Energy I, LLC, R.E. Gas Development, LLC, joined therein by Rex Energy Operating Corp., and for the limited purposes set forth therein, Rex Energy Corporation and Sumitomo Corporation (incorporated by reference to Exhibit 2.5 to our Current Report on Form 8-K filed with the SEC on September 3, 2010).
2.6	Form of Parent Guaranty of Rex Energy Corporation attached and made a part of the Participation and Exploration Agreement, dated August 31, 2010, by and among Summit Discovery Resources II, LLC, Rex Energy I, LLC, R.E. Gas Development, LLC, joined therein by Rex Energy Operating Corp., and for the limited purposes set forth therein, Rex Energy Corporation and Sumitomo Corporation (incorporated by reference to Exhibit 2.6 to our Current Report on Form 8-K filed with the SEC on September 3, 2010).
2.7	Form of Parent Guaranty of Sumitomo Corporation attached and made a part of the Participation and Exploration Agreement, dated August 31, 2010, by and among Summit Discovery Resources II, LLC, Rex Energy I, LLC, R.E. Gas Development, LLC, joined therein by Rex Energy Operating Corp., and for the limited purposes set forth therein, Rex Energy Corporation and Sumitomo Corporation (incorporated by reference to Exhibit 2.7 to our Current Report on Form 8-K filed with the SEC on September 3, 2010).
2.8	First Amendment to Participation and Exploration Agreement, dated September 30, 2010, by and among Summit Discovery Resources II, LLC, Rex Energy I, LLC, R.E. Gas Development, LLC, joined therein by Rex Energy Operating Corp., and for the limited purposes set forth therein, Rex Energy Corporation and Sumitomo Corporation (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K filed with the SEC on October 6, 2010).

Exhibit Number	Exhibit Title
3.1	Certificate of Incorporation of Rex Energy Corporation (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on April 27, 2007).
3.2	Certificate of Amendment to Certificate of Incorporation of Rex Energy Corporation (incorporated by reference to Exhibit 3.2 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on April 27, 2007).
3.3	Amended and Restated Bylaws of Rex Energy Corporation (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K as filed with the SEC on May 11, 2012).
4.1	Form of Specimen Common Stock Certificate of Rex Energy Corporation (incorporated by reference to Exhibit 4.1 to Amendment No. 1 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on June 11, 2007).
4.2	Indenture dated as of December 12, 2012 among Rex Energy Corporation, the Guarantors named therein and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed with the SEC on December 12, 2012).
4.3	Form of 8.875% Senior Notes due 2020 (included in Exhibit 4.1 to our Current Report on Form 8-K filed with the SEC on December 12, 2012, and incorporated herein by reference).
10.1+	Rex Energy Corporation 2007 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to the registrant's Registration Statement on Form S-1/A filed with the SEC on June 11, 2007).
10.2	Consent Decree (incorporated by reference to Exhibit 10.5 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on April 27, 2007).
10.3	Independent Director Agreement with John A. Lombardi dated April 1, 2007 (incorporated by reference to Exhibit 10.6 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on April 27, 2007).
10.4	Summary of oral month-to-month agreement regarding use of airplane between Charlie Brown Air Corp. and Rex Energy Operating Corp. (incorporated by reference to Exhibit 10.13 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on July 6, 2007).
10.5	First Amended and Restated Aircraft Joint Ownership and Management Agreement, dated June 21, 2007, between Charlie Brown Air Corp. and Charlie Brown II Limited Partnership (incorporated by reference to Exhibit 10.18 to Amendment No. 2 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on July 6, 2007).
10.6	Credit Agreement, dated as of September 28, 2007, among Rex Energy Corporation, as Borrower, KeyBank National Association, as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K as filed with the SEC on October 3, 2007).
10.7	Guaranty and Collateral Agreement, dated as of September 28, 2007, made by Rex Energy Corporation and each of the other grantors (as defined therein) in favor of KeyBank National Association, as Administrative Agent (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K as filed with the SEC on October 3, 2007).
10.8	Independent Director Agreement by and between Rex Energy Corporation and John W. Higbee effective as of October 17, 2007 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on October 19, 2007).
10.9*	Summary of Rex Energy Corporation Non-Employee Director Compensation Program.

Exhibit Number	Exhibit Title
10.10+	Form of Nonqualified Stock Option Award Agreement for employee common stock option awards under Rex Energy 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.28 to our Annual Report on Form 10-K filed with the SEC on March 31, 2008).
10.11	Form of Nonqualified Stock Option Award Agreement for non-employee director common stock option awards under Rex Energy 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.29 to our Annual Report on Form 10-K filed with the SEC on March 31, 2008).
10.12+	Form of Stock Appreciation Right Award Agreement under Rex Energy 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.30 to our Annual Report on Form 10-K filed with the SEC on March 31, 2008).
10.13	First Amendment to Credit Agreement, effective as of April 14, 2008, among Rex Energy Corporation, as Borrower, KeyBank National Association as Administrative Agent, and the Lenders signatory thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on April 18, 2008).
10.14	Second Amendment to Credit Agreement, effective December 23, 2008, among Rex Energy Corporation, as Borrower, KeyBank National Association as Administrative Agent, and the Lenders signatory thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on January 9, 2009).
10.15	Operating Agreement of Charlie Brown Air II, LLC dated as of June 26, 2008 (incorporated by reference to Exhibit 10.35 to our Annual Report on Form 10-K/A filed with the SEC on October 9, 2009).
10.16	Third Amendment to Credit Agreement, effective as of April 20, 2009, among Rex Energy Corporation, as Borrower, KeyBank National Association as Administrative Agent, and the Lenders signatory thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on April 27, 2009).
10.17	Participation and Exploration Agreement dated June 18, 2009 by and among Williams Production Company, LLC, Williams Production Appalachia, LLC, Rex Energy I, LLC and R.E. Gas Development, LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on June 24, 2009).
10.18	Tax Partnership Agreement attached and made a part of the Participation and Exploration Agreement dated June 18, 2009 by and among Williams Production Company, LLC, Williams Production Appalachia, LLC, Rex Energy I, LLC and R.E. Gas Development, LLC (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed with the SEC on June 24, 2009).
10.19	Limited Liability Company Agreement of RW Gathering, LLC effective as of June 18, 2009 (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K filed with the SEC on June 24, 2009).
10.20	Settlement Agreement and Release by and between Julia Leib and Lisa Thompson, individually and on behalf of the certified class, on the one hand, and Rex Energy Operating Corp. and PennTex Resources Illinois, Inc., on the other hand, effective December 17, 2009 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on December 22, 2009).
10.21-	Limited Liability Company Agreement of Keystone Midstream Services, LLC, dated December 21, 2009, by and among R.E. Gas Development, LLC, Stonehenge Energy Resources, L.P. and Keystone Midstream Services, LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on December 28, 2009).
10.22-	Contribution Agreement, dated December 21, 2009, by and among R.E. Gas Development, LLC, Stonehenge Energy Resources, L.P. and Keystone Midstream Services, LLC (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed with the SEC on December 28, 2009).

Exhibit Number	Exhibit Title
10.23-	Gas Gathering, Compression and Processing Agreement, dated December 21, 2009, by and between R.E. Gas Development, LLC, Keystone Midstream Services, LLC and Rex Energy Corporation (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K filed with the SEC on December 28, 2009).
10.24	Fourth Amendment to Credit Agreement, effective as of December 18, 2009, among Rex Energy Corporation, as Borrower, KeyBank National Association, as Administrative Agent, and the Lenders signatory thereto (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K filed with the SEC on December 28, 2009).
10.25	Assumption Agreement effective as of December 18, 2009 made by R.E. Gas Development, LLC in favor of KeyBank National Association, as Administrative Agent, and the Lenders party to the Credit Agreement (incorporated by reference to Exhibit 10.5 to our Current Report on Form 8-K filed with the SEC on December 28, 2009).
10.26	Supplement to Guaranty and Collateral Agreement effective as of December 18, 2009 made by Rex Energy Corporation in favor of KeyBank National Association, as Administrative Agent, and the Lenders party to the Credit Agreement (incorporated by reference to Exhibit 10.6 to our Current Report on Form 8-K filed with the SEC on December 28, 2009).
10.27	Master Crude Purchase Agreement by and among certain direct and indirect wholly owned subsidiaries of Rex Energy Corporation and CountryMark Cooperative, dated December 30, 2009. (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on January 5, 2010).
10.28+	Form of Restricted Stock Award Agreement for employee restricted stock awards under Rex Energy 2007 Long-Term Incentive Plan (prior to December 2011) (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on March 31, 2010).
10.29+	Form of Performance Based Restricted Stock Award for employee restricted stock awards under Rex Energy 2007 Long Term Incentive Plan (first effective for awards granted in December 2011) (incorporated by reference to Exhibit 10.32 to our Annual Report on Form 10-K filed with the SEC on March 15, 2012).
10.30+	Form of Service Based Restricted Stock Award Agreement for employee restricted stock awards under Rex Energy 2007 Long-Term Incentive Plan (first effective for awards granted in December 2011) (incorporated by reference to Exhibit 10.33 to our Annual Report on Form 10-K filed with the SEC on March 15, 2012).
10.31	Independent Director Agreement by and between Rex Energy Corporation and Eric L. Mattson effective as of April 30, 2010 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on April 30, 2010).
10.32	Purchase and Sale Agreement dated June 28, 2010 by and between Rex Energy Rockies, LLC and Duncan Oil Partners, LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on July 7, 2010).
10.33	Fifth Amendment to Credit Agreement, effective as of December 18, 2009, among Rex Energy Corporation, as Borrower, KeyBank National Association as Administrative Agent, and the Lenders signatory thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on September 3, 2010).
10.34	First Amendment to Limited Liability Company Agreement of Keystone Midstream Services, LLC, dated September 30, 3010, by and among Keystone Midstream Services, LLC, R.E. Gas Development, LLC, Stonehenge Energy Resources, L.P., and Summit Discovery Resources II, LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on October 6, 2010).

Exhibit Number	Exhibit Title
10.35+	Employment Agreement by and between Patrick McKinney, Rex Energy Corporation and Rex Energy Operating Corp. dated October 1, 2010 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K as filed with the SEC on October 7, 2008).
10.36+	Employment Agreement by and between Thomas C. Stabley, Rex Energy Corporation and Rex Energy Operating Corp. dated October 1, 2010 (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K as filed with the SEC on October 7, 2010).
10.37+	Employment Agreement by and between Daniel J. Churay, Rex Energy Corporation and Rex Energy Operating Corp. dated November 1, 2010 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K as filed with the SEC on November 3, 2010).
10.38-	Confirmation No. 2 under Master Crude Purchase Agreement by and among certain direct and indirect wholly owned subsidiaries of Rex Energy Corporation and CountryMark Cooperative dated January 3, 2011 for period commencing on January 1, 2011 through December 31, 2011 (incorporated by reference to Exhibit 10.42 to our Annual Report on Form 10-K filed with the SEC on March 3, 2011).
10.39+	Separation Agreement by and between Timothy P. Beattie and Rex Energy Operating Corp. dated January 28, 2011 (incorporated by reference to Exhibit 10.43 to our Annual Report on Form 10-K filed with the SEC on March 3, 2011).
10.40+	Rex Energy Corporation Executive Change of Control Policy (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K as filed with the SEC on February 16, 2011).
10.41+	Rex Energy Corporation Executive Severance Policy (incorporated by reference to Exhibit 10.44 to our Annual Report on Form 10-K filed with the SEC on March 15, 2012).
10.42	Form of Non-Employee Director Restricted Stock Award/Phantom Stock Award Agreement under Rex Energy Corporation 2007 Long-Term Incentive Plan (for awards prior to December 2012) (incorporated by reference to Exhibit 10.45 to our Annual Report on Form 10-K filed with the SEC on March 3, 2011).
10.43*	Form of Non-Employee Director Restricted Stock Award/Phantom Stock Award Agreement under Rex Energy Corporation 2007 Long-Term Incentive Plan.
10.44+	Separation Agreement and Complete Release by and between Daniel J. Churay, Rex Energy Corporation and Rex Energy Operating Corporation dated June 9, 2011 (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q as filed with the SEC on August 5, 2011).
10.45-	Settlement Agreement by and among Rex Energy Corporation, Rex Energy I, LLC and certain landowners in Westmoreland County of the Commonwealth of Pennsylvania dated as of May 13, 2011 (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q as filed with the SEC on August 5, 2011).
10.46+	Employment Agreement by and between Jennifer McDonough, Rex Energy Corporation and Rex Energy Operating Corporation effective April 25, 2011 (incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q as filed with the SEC on August 5, 2011).
10.47+	Letter Agreement by and between Thomas C. Stabley and Rex Energy Corporation dated October 10, 2011 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K as filed with the SEC on October 11, 2011).
10.48+	Letter Agreement by and between Patrick M. McKinney and Rex Energy Corporation dated October 10, 2011 (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K as filed with the SEC on October 11, 2011).

Exhibit Number	Exhibit Title
10.49	Natural Gas Sales Agreement between R.E. Gas Development, LLC and BP Energy Company dated as of August 9, 2011 (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q as filed with the SEC on November 8, 2011).
10.50	Sixth Amendment to Credit Agreement, effective as of August 2, 2011, among Rex Energy Corporation, as Borrower, KeyBank National Association, as Administrative Agent, and the Lenders signatory thereto (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q filed with the SEC on November 8, 2011).
10.51	Seventh Amendment to Credit Agreement, effective as of October 3, 2011, among Rex Energy Corporation, as Borrower, KeyBank National Association, as Administrative Agent, and the Lenders signatory thereto (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q filed with the SEC on November 8, 2011).
10.52	Second Lien Credit Agreement dated as of December 22, 2011 among Rex Energy Corporation, as Borrower, KeyBank National Association, as Administrative Agent, Wells Fargo Bank, N.A., as Syndication Agent, UnionBanCal Equities, Inc. and SunTrust Bank, as Co-Documentation Agents and the Lenders signatory thereto (incorporated by reference to Exhibit 10.54 to our Annual Report on Form 10-K filed with the SEC on March 15, 2012).
10.53	Guarantee and Second Lien Collateral Agreement dated as of December 22, 2011 among Rex Energy Corporation and each of the Grantors defined therein in favor of KeyBank National Association, as Administrative Agent (incorporated by reference to Exhibit 10.55 to our Annual Report on Form 10-K filed with the SEC on March 15, 2012).
10.54	Eighth Amendment to Credit Agreement, effective as of December 22,2011, among Rex Energy Corporation, as Borrower, KeyBank National Association as Administrative Agent, and the Lenders signatory thereto (incorporated by reference to Exhibit 10.56 to our Annual Report on Form 10-K filed with the SEC on March 15, 2012).
10.55	Ninth Amendment to Credit Agreement by and among Rex Energy Corporation, KeyBank National Association as Administrative Agent, and the Lenders signatory thereto effective May 7, 2012 (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q filed with the SEC on August 9, 2012).
10.56	First Amendment to Second Lien Credit Agreement by and among Rex Energy Corporation, KeyBank National Association as Administrative Agent, and the Lenders signatory thereto effective May 7, 2012 (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q filed with the SEC on August 9, 2012).
10.57-	Second Amendment to Gas Gathering, Compression and Processing Agreement dated as of May 29, 2012, by and among Keystone Midstream Services, LLC, R.E. Gas Development, LLC and Summit Discovery Resources II, LLC (incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q filed with the SEC on August 9, 2012).
10.58	Tenth Amendment to Credit Agreement by and among Rex Energy Corporation, KeyBank National Association as Administrative Agent, and the Lenders signatory thereto effective September 5, 2012 (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q filed with the SEC on November 9, 2012).
10.59	Second Amendment to Second Lien Credit Agreement by and among Rex Energy Corporation, KeyBank National Association as Administrative Agent, and the Lenders signatory thereto effective September 5, 2012 (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q filed with the SEC on November 9, 2012).
10.60*	Eleventh Amendment to Credit Agreement by and among Rex Energy Corporation, KeyBank National Association as Administrative Agent, and the Lenders signatory thereto effective November 12, 2012.

Exhibit Number	Exhibit Title
10.61*	Third Amendment to Second Lien Credit Agreement by and among Rex Energy Corporation, KeyBank National Association as Administrative Agent, and the Lenders signatory thereto effective November 12, 2012.
10.62	Registration Rights Agreement dated as of December 12, 2012 among Rex Energy Corporation, the Guarantors named therein and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed with the SEC on December 12, 2012).
21.1*	Subsidiaries of the Registrant.
23.1*	Consent of KPMG, LLP.
23.2*	Consent of Malin, Bergquist & Company, LLP.
23.3*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Chief Executive Officer (Principal Executive Officer) pursuant to Section 302 of the Sarbanes-Oxley Act.
31.2*	Certification of Chief Financial Officer (Principal Financial Officer) pursuant to Section 302 of the Sarbanes-Oxley Act.
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act.
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act.
99.1*	Report of Netherland, Sewell & Associates, Inc.
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith.

** Furnished herewith.

\+ Indicates management contract or compensation plan or arrangement.

\- Portions of this exhibit are subject to a request for confidential treatment and have been redacted and filed separately with the Securities and Exchange Commission.

GLOSSARY OF OIL AND NATURAL GAS TERMS

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

Basin. A large natural depression on the earth's surface in which sediments accumulate.

Bbl. One stock tank barrel, of 42 U.S. gallons liquid volume, of crude oil.

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

Bopd. Barrels of oil per day.

Btu or British Thermal Unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The installation of permanent equipment for the production of oil or gas.

Development or Developmental well. A well drilled within the proved boundaries of an oil or gas reservoir with the intention of completing the stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses, taxes and the royalty burden.

Estimated proved reserves. 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, 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.

The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) 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 geosciences and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geosciences, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil 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 geosciences, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

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: (i) 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 (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. 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.

Exploitation. A drilling or other project which may target proved or unproved reserves (such as probable or possible reserves), but generally is expected to have lower risk.

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

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

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

Horizontal drilling. A drilling operation in which a portion of the well is drilled horizontally within a productive or potentially productive formation. This operation usually yields a well which has the ability to produce higher volumes than a vertical well drilled in the same formation.

Injection well or Injection. A well which is used to place liquids or gases into the producing zone during secondary/tertiary recovery operations to assist in maintaining reservoir pressure and enhancing recoveries from the field.

Lease operating expenses. The expenses of lifting oil or gas from a producing formation to the surface, and the transportation and marketing thereof, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, ad valorem taxes and other expenses incidental to production, but excluding lease acquisition or drilling or completion expenses.

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

MBOE. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet of natural gas.

Mcfd. One thousand cubic feet of natural gas per day.

MMBbls. One million barrels of oil or other liquid hydrocarbons.

MMBOE. One million barrels of oil equivalent.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of gas.

MMcfe. One million cubic feet equivalent, determined using the ratio of six Mcf of gas to one Bbl of oil, condensate or gas liquids.

SIGNATURES

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

Dated: March 14, 2013

REX ENERGY CORPORATION

By: /s/ THOMAS C. STABLEY

Thomas C. Stabley
Chief Executive Officer

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

/s/ LANCE T. SHANER **Lance T. Shaner**	Chairman of the Board	March 14, 2013
/s/ THOMAS C. STABLEY **Thomas C. Stabley**	Chief Executive Officer and Director (Principal Executive Officer)	March 14, 2013
/s/ MICHAEL L. HODGES **Michael L. Hodges**	Chief Financial Officer (Principal Financial Officer)	March 14, 2013
/s/ CURTIS J. WALKER **Curtis J. Walker**	Chief Accounting Officer (Principal Accounting Officer)	March 14, 2013
/s/ ERIC L. MATTSON **Eric L. Mattson**	Director	March 14, 2013
/s/ JOHN W. HIGBEE **John W. Higbee**	Director	March 14, 2013
/s/ JOHN A. LOMBARDI **John A. Lombardi**	Director	March 14, 2013
/s/ JOHN J. ZAK **John J. Zak**	Director	March 14, 2013

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COMPANY PARTICULARS

Board of Directors

Lance T. Shaner
Chairman

Thomas C. Stabley
Director, Chief Executive Officer

John W. Higbee
Director and Chairman of Compensation Committee

John A. Lombardi
Director and Chairman of Audit Committee

Eric L. Mattson
Director

John J. Zak
Director and Chairman of Nominating and Governance Committee

Executive Management

Thomas C. Stabley
Chief Executive Officer

Patrick M. McKinney
President and Chief Operating Officer

Michael L. Hodges
Chief Financial Officer

Curtis J. Walker
Chief Accounting Officer

David E. Pratt
Senior Vice President, Exploration Manager

F. Scott Hodges
Senior Vice President, Land

Christina K. Marshall
Senior Vice President, Human Resources and Administration

Jennifer L. McDonough
Vice President, General Counsel and Corporate Secretary

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Telephone: (214) 840-2000
Fax: (214) 840-2297

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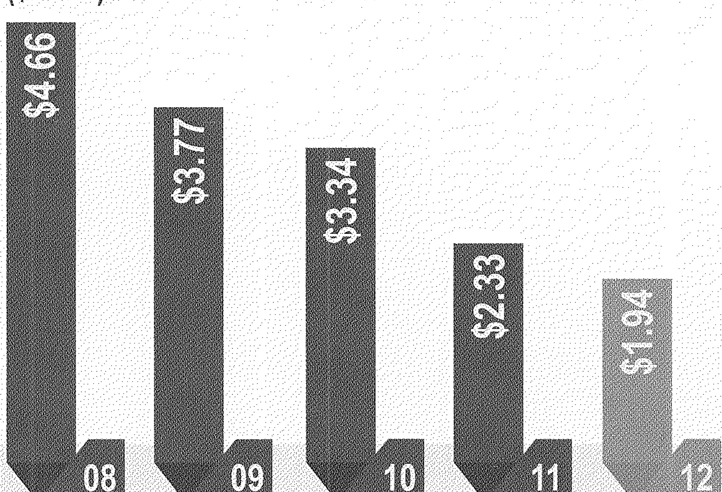
Providence, Rhode Island 02940-3078
Within USA, US territories & Canada
(800) 662-7232
Outside USA, US territories & Canada
(781) 575-4238
www.computershare.com/investor

Annual Meeting
May 8, 2013 at 11:00 a.m.
Hampton Inn & Suites
Williamsburg Square
1955 Waddle Road
State College, PA 16803

Lease Operating Expenses
($/Mcfe)



General and Administrative Expenses
($/Mcfe)

Rex Energy Corporation

476 Rolling Ridge Drive, Suite 300

State College, PA 16801

814-278-7267

www.RexEnergy.com

We are moving the Company's headquarters in April 2013. The Company's address will be: Rex Energy Corporation, 366 Walker Drive, State College, PA 16801.

Forward Looking Statements Certain statements in this report relate to future events, plans or expectations and, as such, constitute forward looking statements. Forward looking statements often contain words such as "plans," "expects," "estimates," "will" or similar expressions. These statements involve known and unknown risks and uncertainties that may cause our actual results or performance to be materially different than those expressed or implied in the forward looking statements. For further information about forward looking statements, including some of the specific factors that may cause such a difference, see the forward looking statements and risk factors discussions in our 2012 Form 10-K. We are not obligated to and do not intend to update or revise any forward looking statements.