KODIAK
OIL & GAS CORP.

ANNUAL REPORT

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: 001-32920

KODIAK OIL & GAS CORP.

(Exact name of registrant as specified in its charter)

Yukon Territory (State or other jurisdiction of incorporation or organization)	N/A (I.R.S. Employer Identification No.)
1625 Broadway, Suite 250 **Denver, Colorado 80202** (Address of principal executive offices)	**(303) 592-8075** (Registrant's telephone number, including area code)

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

Title of Each Class	Name of Exchange on Which Registered
Common Stock	New York Stock Exchange

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 is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference on Part III of this Form 10-K or any amendment to this Form10-K. ☐

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

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

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

At June 29, 2012, the aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $1,794,242,431. The number of shares of the registrant's Common Stock outstanding as of February 27, 2013, was 265,309,314.

DOCUMENTS INCORPORATED BY REFERENCE

Certain portions of the registrant's definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A not later than 120 days after the registrant's fiscal year ended December 31, 2012, in connection with the registrant's 2013 Annual Meeting of Shareholders, are incorporated herein by reference into Part III of this Annual Report on Form 10-K.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The information discussed in this annual report on Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). All statements, other than statements of historical facts, included herein concerning, among other things, planned capital expenditures, increases in oil and gas production, the number of anticipated wells to be drilled or completed after the date hereof, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "believe," "intend," "achievable," "anticipate," "will," "continue," "potential," "should," "could," and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Our results could differ materially from those anticipated in these forward-looking statements as a result of certain factors, including, among others:

- capital requirements and uncertainty of obtaining additional funding on terms acceptable to us;
- unsuccessful drilling and completion activities and the possibility of resulting write-downs;
- price volatility of oil and natural gas prices, and the effect that lower prices may have on our net income and stockholders' equity;
- a decline in oil or natural gas production, and the impact of general economic conditions on the demand for oil and natural gas and the availability of capital;
- geographical concentration of our operations;
- constraints on us as a result of our substantial indebtedness, including restrictions imposed on us under the terms of our credit facility agreement and Senior Notes (defined below), and our ability to generate sufficient cash flows to repay our debt obligations;
- our ability to meet our proposed drilling schedule and to successfully drill wells that produce oil or natural gas in commercially viable quantities;
- financial losses and reduced earnings related to our commodity derivative agreements, and failure to produce enough oil to satisfy our commodity derivative agreements;
- our history of losses;
- adverse variations from estimates of reserves, production, production prices and expenditure requirements, and our inability to replace our reserves through exploration and development activities;
- incorrect estimates associated with properties we acquire relating to estimated proved reserves, the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs of such acquired properties;
- hazardous, risky drilling operations and adverse weather and environmental conditions;
- limited control over non-operated properties;
- reliance on limited number of customers;
- title defects to our properties and inability to retain our leases;
- our ability to successfully develop our large inventory of undeveloped operated and non-operated acreage;
- our ability to retain key members of our senior management and key technical employees;

- constraints in the Williston Basin with respect to gathering, transportation and processing facilities and marketing;
- federal, state and tribal regulations and laws;
- risks relating to managing our growth, particularly in connection with the integration of significant acquisitions;
- impact of environmental, health and safety, and other governmental regulations, and of current or pending legislation;
- developments in the global economy;
- changes in tax laws;
- effects of competition;
- effect of seasonal factors;
- lack of availability of drilling rigs, equipment, supplies, insurance, personnel and oil field services; and
- further sales or issuances of common stock and price volatility of our common stock.

Finally, our future results will depend upon various other risks and uncertainties, including, but not limited to, those detailed in the section entitled "Risk Factors" included elsewhere in this annual report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements in this section and elsewhere in this annual report. Other than as required under securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

Company Overview

Kodiak Oil & Gas Corp. ("Kodiak," "we" or the "Company") is an independent energy company focused on the exploration, exploitation, acquisition and production of crude oil and natural gas in the United States. We have developed an oil and natural gas asset base of proved reserves, as well as a portfolio of development and exploratory drilling opportunities on high-potential prospects. Our oil and natural gas reserves and operations are concentrated in the Williston Basin of North Dakota. We intend to continue to expand our asset base by drilling and completing wells within our current lands as well as evaluating and investing in acquisitions.

The following table summarizes our estimated proved reserves by category as of December 31, 2012, their corresponding pre-tax PV-10 values and our total standardized measure of discounted future net cash flows as of December 31, 2012:

	Gross Wells	Net Wells	Net Remaining Oil (MBbls)	Net Remaining Gas (MMcf)	Net Remaining Oil Equivalent (MBOE)	Pre-Tax PV-10 (1) (in millions)
Proved Developed Producing						
Bakken/TFS	257	117.8	36,029.8	41,476.0	42,942.4	$ 1,360.2
Other Fields	13	3.1	128.2	394.3	193.9	4.1
Total Proved Developed	270	120.9	36,158.0	41,870.3	43,136.3	1,364.3
Proved Undeveloped						
Bakken/TFS	193	113.8	44,771.8	41,253.3	51,647.4	$ 554.8
Other Fields	—	—	—	—	—	—
Total Proved Undeveloped	193	113.8	44,771.8	41,253.3	51,647.4	554.8
Total Proved Reserves	463	234.7	80,929.8	83,123.6	94,783.7	$ 1,919.1
Discounted Future Income Taxes						(310.6)
Standardized Measure of Discounted Future Net Cash Flows						$ 1,608.5

(1) The pre-tax present value of future net cash flows, or PV-10, is a non-GAAP measure because it excludes income tax effects. Management believes that pre-tax cash flow amounts are useful for evaluative purposes since future income taxes, which are affected by a Company's unique tax position and strategies, can make after-tax amounts less comparable. We derive PV-10 based on the present value of estimated future revenues to be generated from the production of proved reserves, net of estimated production and future development costs and future plugging and abandonment costs, using the twelve-month arithmetic average of the first of the month prices without giving effect to hedging activities or future escalation, costs as of the date of estimate without future escalation, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion, amortization and impairment and income taxes, and discounted using an annual discount rate of 10%.

As of December 31 2012, we had approximately 164,700 net acres under lease, of which approximately 154,400 net acres were in the Bakken oil play in the Williston Basin of North Dakota and Montana, as summarized in the following table:

	Total Acreage	
	Gross	**Net**
Williston Basin		
North Dakota	222,693	151,895
Montana	5,464	2,489
	228,157	154,384
Green River Basin		
Wyoming	24,056	5,984
Colorado	11,002	4,319
	35,058	10,303
Acreage Totals	263,215	164,687

Since 2010, we have increased our average daily oil and natural gas sales volumes significantly from 1,259 to 14,356 BOE/d as summarized in the following table.

	For the Years Ended December 31,		
	2012	**2011**	**2010**
Sales Volume (Total):			
Oil (MBbls)	4,704.1	1,344.5	432.3
Gas (MMcf)	3,302.0	522.7	162.9
Sales volumes (MBOE)	5,254.4	1,431.6	459.5
Average Daily Sales			
Oil (Bbls)	12,853	3,684	1,184
Gas (Mcf)	9,022	1,432	446
Sales volumes (BOE)	14,356	3,922	1,259

In 2012, we incurred total capital costs of approximately $1.5 billion, including $636.7 million related to our January 2012 Acquisition (as defined below). Our drilling and completion capital expenditures in 2012 totaled $810.4 million for the drilling of 70.7 net wells and completion of 62.6 net wells, compared to our budgeted expenditures of $738.0 million. Our expenditures related to our operated properties were $664.5 million, compared to the budgeted amount of $618.0 million, while our expenditures related to non-operated were $145.9 million, compared to the budgeted amount of $120.0 million. In 2012, we exceeded our capital budget by $72.4 million primarily as a result of increased drilling due to drilling efficiencies gained in our operations, higher than expected capital expenditures in our non-operated properties and favorable weather conditions allowing for more activity than was originally planned.

Our capital expenditures budget for 2013 is $775.0 million which is expected to fund the drilling of 75.0 net wells, the installation of related midstream infrastructure and leasehold acquisitions. This budget anticipates spending $600.0 million operating six to seven drilling rigs, and we expect to drill and complete 61.0 net operated wells. Also included in the 2013 budget is $140.0 million allocated to non-operated capital expenditures where we expect to participate in the drilling and completion of 14.0 net non-operated wells. We expect to fund our 2013 capital program through existing cash on hand, our expected cash flows from operations, and our borrowing capacity expected to be available under our credit facility.

For the full year 2013, we project oil and gas sales volumes to average between 29,000 to 31,000 BOE/d, based upon the activities contemplated under our 2013 CAPEX budget, as discussed above. This production level would represent over 100% growth in sales volumes as compared to 2012. The projected exit rate for 2013 sales volumes is expected to range from 38,000 to 40,000 BOE/d.

The Company was incorporated on March 17, 1972 in the Province of British Columbia, Canada, under the name "Pacific Talc Ltd." pursuant to the Company Act (British Columbia). On November 12, 1998, the name of the Company was changed to "Columbia Copper Company Ltd." On September 28, 2001, the Company was continued from British Columbia to the Yukon Territory and the name of the Company was changed to "Kodiak Oil & Gas Corp." On September 23, 2003, we incorporated a wholly-owned subsidiary, Kodiak Oil & Gas (USA) Inc. in Colorado. Kodiak Oil & Gas (USA) Inc. was formed to hold all of our US oil and gas properties located in the United States.

For a summary of Kodiak's financial information, including revenues from external customers, information on net income and loss, long-lived assets, and total assets, see "Item 6. Selected Financial Data" and "Item 8. Financial Statements and Supplementary Data."

Our Strategy

Our business strategy is to create value for our stakeholders by growing reserves, production volumes and cash flow utilizing advanced development, drilling and completion technologies to systematically explore for, develop and produce oil and natural gas reserves, and evaluate strategic acquisitions. Key elements of our business strategy include:

Focus on Developing our Williston Basin Leasehold Position. We intend to continue developing our acreage position in the Williston Basin in order to enhance the value of its resource potential. Due to the continued favorable results from our producing wells and current commodity prices, we intend to concentrate all of our 2013 capital expenditures in the Williston Basin. We believe that our experience in the application of advanced drilling and completion techniques, our access to drilling rigs and oil field services, our contiguous acreage positions, along with the high working interests that we maintain in our properties provide us with a competitive advantage in developing our approximately 154,400 net acres that are prospective for the Middle Bakken and Three Forks ("TFS") formations.

Leverage our Experience in the Williston Basin. We continue to develop expertise in drilling and completion technologies in horizontal drilling and multi-stage isolated fracture stimulations. We continue to refine our drilling and completion techniques, as well as monitor the results of other operators, in an effort to enhance well performance and the associated estimated ultimate recoveries and rates of return.

Retain Operational Control and Significant Working Interest. We typically seek to maintain operational control of our development and drilling activities. As operator, we retain more control over the timing, selection and process of drilling prospects, and completion design, which enhances our ability to maximize our return on invested capital and gives us greater control over the timing, allocation and amounts of our capital expenditures. Retaining operational control also gives us the ability to control the financing, construction and operation of infrastructure related to our production operations.

Evaluate Acquisitions in the Williston Basin. We will continue to evaluate strategic acquisitions in the Williston Basin. Through our acquisitions, we have captured economies of scale that allow us to obtain services in a timely manner in the current highly competitive environment.

Maintain Financial Flexibility. Our goal is to remain financially strong, yet flexible, through the prudent management of our balance sheet and appropriate management of commodity price volatility. Our strategy to retain operational control provides for financial flexibility and allows us to manage the timing of a substantial portion of our capital expenditure program.

Our Competitive Strengths

We believe we possess a range of competitive strengths, including:

Substantial Leasehold Position in the Core of the Williston Basin. As of December 31, 2012, we hold approximately 154,400 net leasehold acres in the Williston Basin. Our concentrated acreage position is prospective for the Middle Bakken and TFS formations. We believe the results of our active drilling program and drilling activity by other exploration and production companies have significantly improved the risk profile of our concentrated acreage position.

Oil-Weighted Production and Reserves. As of December 31, 2012, approximately 85% of our 94.8 MMBOE net proved reserves are comprised of oil, with a vast majority of all of the gas reserves coming from associated gas.

Large, Multi-Year Drilling Inventory Targeting Primarily Oil Production. We, along with other operators, continue to evaluate well bore spacing in both the Middle Bakken and TFS formations. Based upon the early work that has been completed and with our current rig count, we believe that we have in excess of ten years worth of drilling activities with a current estimate of 1,140 gross (787 net) operated drillable locations remaining. In addition, the Company estimates it has approximately 160 net non-operated drillable locations remaining. The drilling inventory primarily assumes 1,280-acre drilling units that have been substantially delineated across the Company's acreage positions and are economic with today's oil prices and service costs. As additional work is completed in both the Middle Bakken and TFS formations, we believe that the number of drillable locations could increase.

High Operatorship and Operational Scale. We have maintained operatorship over the majority of our acreage, thereby providing us increased operational scale and efficiencies. We plan to operate six to seven drilling rigs during 2013 and project to drill approximately 61.0 net operated wells in 2013. With our expected drilling activity, we anticipate utilizing up to two full-time 24-hour completion crews. As we continue to develop our acreage position, we believe the operational scale gained from this level of activity should enable us to realize cost efficiencies. By operating our properties, we retain the ability to adjust our capital expenditure program based on well economics and rates of return.

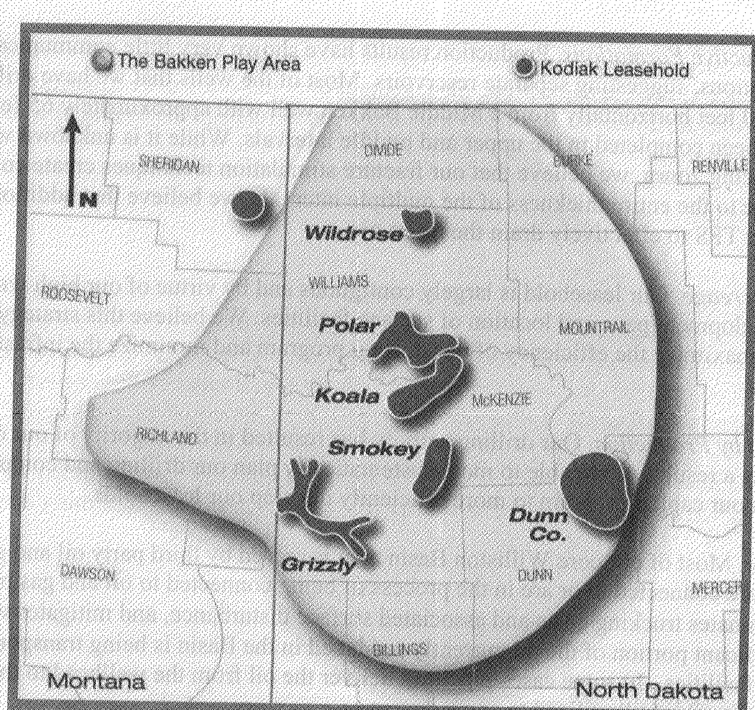
Access to Infrastructure and Service Base Across Our Core Areas. Our properties in the Williston Basin are located where we have access to oil and gas pipelines and rail loading facilities that allow transportation to various markets. Furthermore, we have constructed water disposal facilities throughout our properties over the past few years, thereby reducing our dependence on third party services. In addition, our access to oilfield services has continued to improve such that, today, most services are readily available, and the quality of services has improved. As a result of the increase in infrastructure and improved availability of oilfield services, we expect our operating efficiencies to continue to improve while enhancing our rates of return.

Experienced Management and Technical Teams. Our management and technical teams have an average of more than 25 years of industry experience, primarily in the Rocky Mountains. The team is responsible for our being an early mover in the acquisition of acreage in the Williston Basin and identifying the benefits of operational scale in the region.

Our Area of Operation

Williston Basin—154,400 net acres

The Williston Basin contains nearly all of our total proved reserves as of December 31, 2012. The following map depicts our primary areas of operations within the Williston Basin:



Our Williston Basin acreage is located primarily in Dunn, McKenzie and Williams counties, of North Dakota. Our primary geologic target is the Bakken Pool where our primary objective is the dolomitic, sandy interval between the two Bakken Shales at an approximate vertical depth of 10,300-11,300 feet and the TFS that is present immediately below the lower Bakken Shale. The Williston Basin also produces from many other formations including, but not limited to, the Mission Canyon, Nisku and Red River. We currently operate a seven-rig drilling program and anticipate operating six to seven drilling rigs for the majority of 2013. Our joint venture partner on our Dunn County acreage continues to operate with two drilling rigs on the lands it operates. We anticipate having a working interest of up to 50% in the wells to be drilled by these two non-operated rigs. In addition to our operated rigs and the joint venture rigs, we continue to participate in non-operated interests drilled by other operators.

Our operations are in an area that we believe has higher reservoir pressure and a high degree of thermal maturity, which is prospective for both the Middle Bakken and multiple benches within the TFS. Based on recent drilling results, along with internal and third party reserve engineering analysis, we expect wells in this area to have economic ultimate recoveries ("EURs") that range from 450 to over 1,000 MBOE.

Important aspects of our drilling program in this core Williston Basin area include the following:

Long Laterals. Based upon our exploration efforts, we believe that the internal rate of return of the longer 10,000 foot laterals is higher than we achieved with our shorter laterals of 5,000 feet or less. Although utilizing long laterals is more expensive, we estimate that the additional costs of drilling the longer lateral and adding more fracture stimulation stages is offset by the associated incremental increase in oil production.

Multi-Well Pads. We have continued to drill on pads with two to four wells. As we move into the development stage of drilling, we expect the average number of wells drilled from each pad will increase. There are many advantages to pad drilling, such as reduced costs of mobilization and demobilization of our drilling rigs as a result of fewer moves, and the reduced number of drilling pads minimizes the impact on the surface locations. Furthermore, we have seen efficiencies in our completion work as we eliminate mobilization and demobilization time for our pressure pumping company and have the ability to complete multiple wells at the same time through the use of zipper fracturing techniques. Utilization of zipper fracturing techniques allows the simultaneous completion of two wells by alternating perforation and pressure pumping operations.

Wellbore Spacing. We have commenced drilling operations on two pilot programs to test tighter well bore density in our Polar and Smokey operating areas in the Williston Basin. In these two areas, we intend to drill up to 12 wells within a drilling spacing unit (DSU) with six wells targeting the Middle Bakken and six wells targeting the known productive intervals of the TFS.

Multiple Productive Formations. Production results have shown very little communication between the Middle Bakken and TFS formations, suggesting separate reservoirs. Most of the wells that we have drilled to date in the TFS were positioned less than 700 feet horizontally from a Middle Bakken well with approximately 65 feet of vertical separation. Our wells in the TFS have been completed in the upper and middle intervals. While it is unknown whether these intervals are entirely separate producing zones, we believe that our fracture stimulation techniques create communication between these intervals. However, due to the entire thickness of the multiple intervals, we believe that additional wells will be required to be drilled within the entire TFS to effectively drain the reservoir.

Contiguous Acreage. Our leasehold is largely contiguous and by virtue of our high working interest and operatorship, we can control the development pace and location of surface facilities. We believe this strategy, combined with pad drilling and long laterals, will maximize the efficiency of our drilling program and minimize the infrastructure required to connect our wells to sales pipelines.

Acreage Held by Production. Our drilling activity has resulted in the majority of our operated drilling units being held by production. As a result, we are able to more systematically plan our drilling and completion activities. This provides increased flexibility in our capital program to more efficiently develop our leaseholds.

Infrastructure. Most of our core Williston Basin area is served by third party oil and gas gathering systems. The majority of our wells are connected to or are in the process of being connected to oil and gas pipelines. Moving oil and gas through pipelines eliminates trucking costs and associated surface disturbance, and mitigates weather related production interruptions. A significant portion of the oil currently produced in the Basin is being transported to refineries through the utilization of railroad facilities. In some cases pipelines deliver the oil from the wellhead to the rail facilities, however in some situations trucking of the oil is still utilized to some degree.

We continue to make improvements in the volumes of gas delivered to sales. However, these volumes continue to be limited by insufficient plant capacity. Plant capacity is necessary to process the gas and strip out the high liquids content. As the capacity of natural gas pipelines and related processing facilities continues to increase, we expect to be able to capture additional revenue generated from the sale of associated natural gas and eliminate any significant flaring of gas.

Additionally, in 2012, we drilled and began operating four water disposal wells, and we expect to drill and complete four additional water disposal wells in 2013. These disposal wells, in combination with planned water gathering systems, should allow us to reduce operating costs as we eliminate trucking costs and avoid third party disposal costs.

Our Oil and Gas Reserves

As of December 31, 2012, we had estimated proved reserves of 80.9 MMBbls of oil and 83.1 Bcf of natural gas with a present value discounted at 10% of $1.9 billion based on pricing described below, before income tax effect, or $1.6 billion after the effect of income taxes (Refer to Item 7 under the heading PV-10 of this Annual Report for further discussion regarding the use of this Non-GAAP measure). This is an increase of 127% over our 2011 crude oil reserves and 225% over our 2011 natural gas reserves. Our reserves are comprised of 85% crude oil and 15% natural gas on an energy equivalent basis.

All of our reserves are located within the continental United States with 99.8% in the Williston Basin in North Dakota and Montana. Netherland Sewell & Associates, Inc. ("NSAI"), our independent petroleum engineering consulting firm, prepared our estimated reserves as of December 31, 2012, 2011 and 2010. Reserve estimates are inherently imprecise and remain subject to revisions based on production history, results of additional exploration and development drilling, results of secondary and tertiary recovery applications, prevailing oil and natural gas prices, and other factors. You should read the notes following the table below and the information following the notes to our audited financial statements for the years ended December 31, 2012 and 2011 included in this Annual Report in conjunction with the following reserve estimates:

	As of December 31,	
	2012 (2)	2011 (3)
Proved Developed Oil Reserves (MBbls)	36,158.0	13,178.8
Proved Undeveloped Oil Reserves (MBbls)	44,771.8	22,396.7
Total Proved Oil Reserves (MBbls)	80,929.8	35,575.5
Proved Developed Gas Reserves (MMcf)	41,870.3	8,956.8
Proved Undeveloped Gas Reserves (MMcf)	41,253.3	16,582.4
Total Proved Gas Reserves (MMcf)	83,123.6	25,539.2
Total Proved Oil Equivalents (MBOE)(1)	94,783.7	39,832.1
Present Value of Estimated Future Net Revenues After Income Taxes, Discounted at 10%(4) (In thousands)	$ 1,608,527	$ 659,975

(1) We converted MMcf to MBOE at a ratio of six Mcf to one barrel of oil.

(2) The values for the 2012 oil and gas reserves are based on the 12 month arithmetic average first of month price January through December 31, 2012 crude oil price of $94.68 per barrel (West Texas Intermediate price) and natural gas price of $2.58 per MMBtu (Questar Rocky Mountains price) or $2.77 per MMBtu (Northern Ventura price). All prices are then further adjusted for transportation, quality and basis differentials. The average resulting price used as of December 31, 2012 was $82.84 per barrel of oil and $5.73 per Mcf for natural gas.

(3) The values for the 2011 oil and gas reserves are based on the 12 month arithmetic average first of month price January through December 31, 2011 crude oil price of $95.99 per barrel (West Texas Intermediate price) and natural gas price of $3.94 per MMBtu (Questar Rocky Mountains price) or $4.17 per MMBtu (Northern Ventura price). All prices are then further adjusted for transportation, quality and basis differentials. The average resulting price used as of December 31, 2011 was $88.40 per barrel of oil and $5.50 per Mcf for natural gas.

(4) The Present Value of Estimated Future Net Revenues After Income Taxes, Discounted at 10%, is referred to as the "Standardized Measure." There is a $310.6 million tax effect in 2012 and a $190.7 million tax effect in 2011. For more information, please refer to *Note 15—Supplemental Oil and Gas Reserve Information (Unaudited)* under Item 8 in this Annual Report.

The table below summarizes our 2012 reserves by field, operating area and categorization as of December 31, 2012, along with the remaining estimated reserves:

	Gross Wells	Net Wells	Net Remaining Oil (MBbls)	Net Remaining Gas (MMcf)	Net Remaining Oil Equivalent (MBOE)	Percent of total Proved Reserves
Proved Developed Producing						
Dunn County	75	38.1	13,120.5	10,505.4	14,871.4	15.7%
Smokey/Koala	77	37.2	12,304.0	17,024.1	15,141.3	16.0%
Polar	84	33.5	9,771.3	13,032.4	11,943.4	12.6%
Other	21	9.0	834.0	914.1	986.3	1.0%
Bakken/TFS	257	117.8	36,029.8	41,476	42,942.4	45.3%
Other Fields	13	3.1	128.2	394.3	193.9	0.2%
Total Proved Developed	270	120.9	36,158.0	41,870.3	43,136.3	45.5%
Proved Undeveloped						
Dunn County	69	39.6	15,565.8	11,793.1	17,531.3	18.5%
Smokey/Koala	56	36.1	13,688.4	15,561.0	16,281.9	17.2%
Polar	62	34.3	14,484.5	13,436.4	16,723.9	17.6%
Other	6	3.8	1,033.1	462.8	1,110.3	1.2%
Bakken/TFS	193	113.8	44,771.8	41,253.3	51,647.4	54.5%
Other Fields	—	—	—	—	—	—%
Total Proved Undeveloped	193	113.8	44,771.8	41,253.3	51,647.4	54.5%
						—%
Total Proved Reserves	463	234.7	80,929.8	83,123.6	94,783.7	100.0%

The increase in our total proved reserves in 2012 in the amount of 54,951.6 MBOE is a result of our drilling and completion activity on Bakken properties and our January 2012 Acquisition. We drilled a total of 146 gross (70.7 net) wells and completed 124 gross (62.6) net wells, thereby incurring a net total of $810.4 million in capital expenditures for these operations. Included in the 146 gross wells drilled were 77 gross (13.6 net) wells drilled by third parties in which we have non-operated interests. In addition, we acquired 70 gross (41.7 net) wells and 11,891.3 MBOE of proved reserves through our January 2012 Acquisition.

Largely as a result of our drilling program that evaluated both the Middle Bakken and Three Forks formations and our January 2012 Acquisition, we increased the number of proved undeveloped (PUD) locations from 93 (57.1 net) at year-end 2011 to 193 (113.8 net) at year-end 2012. These PUD locations offset our existing producing wells or are in DSU's that offset producing wells.

Our total PUD reserves as of December 31, 2012 were 51.6 MMBOE, which represents 54.5% of our total proved reserves as compared to 25.2 MMBOE or 63% of our total proved reserves at December 31, 2011. At year-end 2011, PUD reserves were attributed to 93 gross locations. Of these 93 gross locations, 47 gross wells were drilled, completed and placed on production during 2012 through expenditures of $397.5 million, 45 locations remain undrilled but are in various stages of preparation and permit acquisition and are expected to be drilled over the next year, and one is no longer classified as proved. No PUD locations have been classified as such for more than three years.

Controls Over Reserve Report Preparation, Technical Qualifications and Technologies Used

Our year-end reserve report was prepared by NSAI based upon a review of property interests being appraised, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, geoscience and engineering data, and other information we provided to them. To ensure accuracy and completeness of the data prior to submission to NSAI, the information we provide is reviewed by the following persons with the following qualifications:

- Senior Reservoir Engineer, Wally O'Connell: Mr. O'Connell, a Registered Professional Engineer, is our Reserves Manager and has over 35 years of experience in the oil and gas industry in the areas of engineering and reserves management. He has worked for us since 2007 in the role of Reserves Manager. Prior to such time, he served as Exploitation Manager-Wattenberg Area for both Anadarko Petroleum Corporation from 2006 to 2007 and Kerr-McGee Rocky Mountain Corporation from 1998 to 2006. Prior to such time, he served in a variety of lead reservoir and petroleum engineering positions at various companies, including Questa Engineering Corporation, Whiting Petroleum Corporation and Nicor Exploration Company. He received a Bachelor of Science in Petroleum Engineering from Montana College of Mineral Science and Technology in 1972.
- Executive Vice President of Operations, Russell Branting: Dr. Branting has served as our Operations Manager since June 2007. He has more than 20 years of experience focused throughout the Rocky Mountain region. He has served in various positions in petroleum engineering and operations with Western Gas Resources, Inc., Tesco Underbalanced Drilling Services, Chevron USA, Inc., and Snyder Oil Corporation. He was most recently the Rocky Mountain Drilling Engineering Manager for Anadarko Petroleum Corp., where he was responsible for managing all operations ongoing in the Greater Green River Business Unit, deep Powder River Basin Business Unit and Exploration team. Dr. Branting earned his Ph. D. in Petroleum Engineering from the University of Wyoming in 1993.
- Chief Operating Officer, James Catlin: Mr. Catlin has over 30 years of geologic experience, primarily in the Rocky Mountain region. He has served as a director of the Company since February 2001 and Chief Operating Officer since June 2006. Mr. Catlin was an owner of CP Resources LLC, an independent oil and natural gas company, from 1986 to 2001. Mr. Catlin was a founder of Deca Energy and served as its Vice-President from 1980 to 1986. He worked as a district geologist for Petroleum Inc. and Fuelco prior to such time. He received Bachelor of Arts and Masters degrees in Geology from the University of Northern Illinois in 1973.
- President and Chief Executive Officer, Lynn Peterson: Mr. Peterson has approximately 30 years of experience in the oil and gas industry. He has served as a director of the Company since November 2001 and President and Chief Executive Officer since July 2002. He was an owner of CP Resources, LLC, an independent oil and natural gas company, from 1986 to 2001. Mr. Peterson served as Treasurer of Deca Energy from 1981 to 1986. Mr. Peterson was employed by Ernst and Whinney as a certified public accountant prior to this time. He received a Bachelor of Science in Accounting from the University of Northern Colorado in 1975.

The reserves estimates shown herein have been independently evaluated by Netherland, Sewell & Associates, Inc., a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Dan Paul Smith and Mr. John Hattner. Mr. Smith has been practicing consulting petroleum engineering at NSAI since 1980. Mr. Smith is a Licensed Professional Engineer in the State of Texas (License No. 49093) and has over 30 years of practical experience in petroleum engineering and in the estimation and evaluation of reserves. He graduated from Mississippi State University in 1973 with a Bachelor of Science Degree in Petroleum Engineering. Mr. Hattner has been practicing consulting petroleum geology at NSAI since 1991. Mr. Hattner is a Licensed Professional Geoscientist in the State of Texas, Geology, (License No. 559) and has over 30 years of practical experience in petroleum geosciences, with over 20 years experience in the estimation and evaluation of reserves. He graduated from University of Miami, Florida, in 1976 with a Bachelor of Science Degree in Geology; from Florida State University in 1980 with a Master of Science Degree in Geological Oceanography; and from Saint Mary's College of California in 1989 with a Master of Business Administration Degree. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are decline curve analysis, advance production type curve matching, petro-physics/log analysis and analogy. Some combination of these methods was used to determine reserve estimates in substantially all of our fields.

For more information regarding our oil and gas reserves, please refer to *Note 15—Supplemental Oil and Gas Reserve Information (Unaudited)*, under in Item 8 in this Annual Report.

Our Drilling Activity

The following table sets forth the number and type of wells that we completed during the years ended December 31, 2012, 2011 and 2010. All of our drilling activities are conducted on a contract basis by independent drilling contractors. We do not own any drilling equipment.

	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Development wells, completed as:						
Oil wells	121	62.3	35	15.4	14	5.7
Gas wells	3	0.3	1	0.1	—	—
Non-Productive(1)	—	—	—	—	—	—
Exploratory wells, completed as:						
Oil wells	—	—	—	—	2	0.8
Gas wells	—	—	—	—	—	—
Non-Productive(1)	—	—	—	—	—	—
Total	124	62.6	36	15.5	16	6.5

(1) A non-productive well (also known as a dry hole) is a well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

During 2012, we participated in drilling 146 gross (70.7 net) wells and we completed 124 gross (62.6 net) as producers. This compares to 47 gross (24.6 net) wells drilled and 36 gross (15.5 net) wells completed in 2011. As of December 31, 2012, we had 68 gross (39.5 net) wells in progress, none of which were classified as such at December 31, 2011. Of these, 34 gross wells (15.5 net) were drilled and have either been scheduled for completion during early 2013 or are part of multi-well pads that are expected to be completed after all the wells have been drilled on each shared pad. This includes 18 gross (14.0 net) operated wells.

Productive Wells

As part of our corporate strategy, we seek to operate our wells where possible and to maintain a high level of participation in our wells by investing our own capital in drilling operations. The following table summarizes our productive wells as of December 2012, all of which are located in the Rocky Mountain region of the United States. Productive wells are wells that are producing or capable of producing, including shut-in wells.

	Operated		Non-operated		Total	
	Gross	Net	Gross	Net	Gross	Net
Williston Basin						
Oil and associated gas wells	139	103.5	129	18.4	268	121.9
Wyoming/Colorado						
Gas wells	—	—	10	1.4	10	1.4
Total	139	103.5	139	19.8	278	123.3

Our Leasehold

As of December 31, 2012, we had several hundred lease agreements representing approximately 263,200 gross and 164,700 net acres.

In the Williston Basin of North Dakota and Montana, as of December 31, 2012, we owned an interest in approximately 228,200 gross acres and 154,400 net acres. The majority of our Williston Basin leaseholds (approximately 121,400 net acres) is held primarily under fee and federal leases. These leases typically carry a primary term of 3 to 10 years with landowner royalties of approximately 12.5% to 20.0%. In most cases, we obtain "paid up" fee leases, which do not require annual delay rentals. The federal lands require annual delay rentals of $1.50 to $2.00 per net acre.

Our remaining Williston Basin leaseholds of approximately 33,000 net acres, in Dunn County, North Dakota is entirely encompassed by the Fort Berthold Indian Reservation which is held in trust and administered by the Bureau of Indian Affairs (BIA) on behalf of the individual members of the Hidatsa, Mandan and Arikara tribes, collectively known as the Three Affiliated Tribes. Typically these lands are acquired through private negotiations with the individual land owners and the Three Affiliated Tribes and have a primary lease term of five years. In most cases we have one to three years remaining on the primary term of these leases. Approximately 30% of these lands are encompassed within federal operating units approved by the Bureau of Land Management ("BLM") that allow for the orderly exploration and development. The land owner typically retains an 18% landowner royalty. In most cases, these lands require an annual delay rental of $2.50 per net acre.

In the Green River Basin, we own approximately 35,100 gross acres and 10,300 net acres. The majority of our acreage in Wyoming and Colorado is located on federal lands administered by BLM. Typically these lands are acquired through a public auction and have a primary lease term of ten years. The U.S. Department of the Interior normally retains a 12.5% royalty interest in these lands. Most of our lands in this area are encompassed within federal operating units approved by the BLM that allow for the orderly exploration and development of the federal lands. In most cases, these federal lands require an annual delay rental of $1.50 per net acre.

The following table sets forth our gross and net acres of developed and undeveloped oil and natural gas leases as of December 31, 2012:

	Undeveloped Acreage(1)		Developed Acreage(2)		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Williston Basin						
North Dakota	95,433	66,460	127,260	85,435	222,693	151,895
Montana	-	-	5,464	2,489	5,464	2,489
	95,433	66,460	132,724	87,924	228,157	154,384
Green River Basin						
Wyoming	14,940	4,159	9,116	1,825	24,056	5,984
Colorado	8,028	3,067	2,974	1,252	11,002	4,319
	22,968	7,226	12,090	3,077	35,058	10,303
Acreage Totals	118,401	73,686	144,814	91,001	263,215	164,687

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

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

We believe we have satisfactory title, in all material respects, to substantially all of our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Substantially all of our proved oil and natural gas properties are pledged as collateral for borrowings under our credit facility.

Substantially all of the leases summarized in the preceding table will expire at the end of their respective primary terms unless (i) we have obtained production from the acreage subject to the lease prior to the end of the primary term, in which event the lease will remain in effect until the cessation of production; or (ii) the existing lease is renewed; or (iii) it is contained within a Federal unit. Based on our current drilling plans we do not expect to lose any material acreage through expiration. The following table sets forth the gross and net acres of undeveloped land subject to leases that will expire during the current year and the following three years and have no options for renewal or are not included in Federal units:

	Expiring Acreage	
Year Ending	Gross	Net
December 31, 2013	14,380	11,899
December 31, 2014	34,663	22,125
December 31, 2015	12,835	7,208
Total	61,878	41,232

Crude Oil and Natural Gas Market and Major Customers

The principal products produced by us are crude oil and natural gas. These products are marketed and sold primarily to purchasers that have access to nearby pipeline facilities, refineries or other markets. Typically, both crude oil and natural gas are sold at the wellhead under contracts at negotiated prices based upon factors normally considered in the industry such as distance from well to pipeline, pressure, and quality. We currently have no long- term fixed-price physical delivery contracts in place.

Commensurate with our growth in oil production, we have diversified our oil purchasers. The sales of our crude oil are to third-party marketing companies and a regional pipeline entity that also sells to these and other marketing companies. During the year ended December 31, 2012, we had sales to three purchasers that exceeded 10% of our total oil and gas revenue, whereby such purchasers purchased 27%, 17% and 16%, respectively, of our total oil and gas revenue. Although a substantial portion of our production is purchased by these customers, we do not believe the loss of any one customer would have a material adverse effect on our business as other customers would be accessible to us.

Our results of operations and financial condition are significantly affected by oil and natural gas commodity prices, which can fluctuate dramatically. The market for oil and natural gas is beyond our control and prices are difficult to predict. We currently use financial hedges to limit our overall exposure to fluctuations in oil prices but the hedging arrangements may also reduce our potential cash flows by limiting our exposure to commodity price increases. Our hedges are intended to mitigate the risk of a reduction in cash flows that may affect our ability to meet our obligations and capital expenditure budget while at the same time ensuring an acceptable rate of return on our investments. Our total volumes that can be hedged are limited under our credit facility to 85% to 90% of our forecasted production from our proved oil and gas reserves.

Because we do not currently have firm capacity on pipelines or rail loading facilities that take oil and gas out of the Williston Basin, we will continue to be affected by changes in the price received locally versus prices at quoted market centers, including West Texas Intermediate (WTI). This differential can vary widely because of changes in supply and demand locally and at the market centers as well as the utilization of transportation capacity between these points. During 2012, we experienced differentials ranging from $3.30 per barrel to $19.62 per barrel. We are not currently able to hedge this differential using financial instruments, which reduces the effectiveness of our hedges that are based on WTI prices.

Competition

The oil and gas industry is intensely competitive, particularly with respect to the acquisition of prospective oil and natural gas properties and oil and natural gas reserves. Our ability to effectively compete is dependent on our geological, geophysical and engineering expertise, and our financial resources. We must compete against a substantial number of major and independent oil and natural gas companies that have larger technical staffs and greater financial and operational resources than we do. Many of these companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also have refining operations, market refined products and generate electricity. We also compete with other oil and natural gas companies to secure drilling rigs and other equipment necessary for drilling and completion of wells. As crude oil and natural gas prices decline, access to additional drilling equipment and completion services becomes more available. Conversely, as commodity prices increase, drilling equipment, may be in short supply from time to time.

Seasonality

Winter weather conditions and lease stipulations can limit or temporarily halt our drilling and producing activities and other oil and natural gas operations. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs. Such seasonal anomalies can also pose challenges for meeting our well drilling objectives and may increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay or temporarily halt our operations.

Governmental Regulations and Environmental Laws

Regulation of Oil and Gas Operations

Our oil and natural gas exploration, production and related operations are subject to extensive laws and regulations promulgated by federal, state, tribal and local authorities and agencies. These laws and regulations often require permits for drilling operations, drilling bonds and reports concerning operations, and impose other requirements relating to the exploration for and production of oil and natural gas. Many of the laws and regulations govern the location of wells, the method of drilling and casing wells, the plugging and abandoning of wells, the restoration of properties upon which wells are drilled, temporary storage tank operations, air emissions from flaring, compression, the construction and use of access roads, sour gas management and the disposal of fluids used in connection with operations.

Our operations are also subject to various conservation laws and regulations. These laws and regulations govern the size of drilling and spacing units or proration units, the density of wells that may be drilled in oil and natural gas properties and the unitization or pooling of oil and natural gas properties. In this regard, some states allow the forced pooling or integration of lands and leases to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is primarily or exclusively voluntary, it may be more difficult to form units and therefore more difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose specified requirements regarding the ratability of production. On some occasions, tribal and local authorities have imposed moratorium or other restrictions on exploration and production activities that must be addressed before such activities can proceed.

The failure to comply with any such laws and regulations can result in substantial penalties. In addition, the effect of all these laws and regulations may limit the amount of oil and natural gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. Although we believe we are in substantial compliance with current applicable laws and regulations relating to our oil and gas operations, we are unable to predict the future cost or impact of complying with such laws and regulations because such laws and regulations are frequently amended or reinterpreted. The increasing regulatory burden on the oil and natural gas industry will most likely increase our cost of doing business and may affect our profitability, which could have a material adverse effect on our business, financial condition and results of operations.

Environmental Regulation

Our operations and properties are subject to extensive and changing federal, state, tribal and local laws and regulations relating to protection of the environment, wildlife protection, historic preservation, and health and safety. The recent trend in environmental legislation and regulation is generally toward stricter standards, and we expect that this trend will continue. Among other things, these laws and regulations:

- require the acquisition of permits or other authorizations before construction, drilling and certain other activities;
- require environmental reviews and assessments of proposed actions prior to the issuance of permits or the granting of governmental approvals;
- limit or prohibit construction, drilling and other activities on specified lands within wilderness and other protected areas; and
- impose substantial liabilities for pollution resulting from our operations.

The various environmental permits required for our operations may be subject to revocation, modification and renewal by issuing authorities. Governmental authorities have the power to enforce their regulations, and violations are subject to fines or injunctions, or both. We believe that we are in substantial compliance with current applicable environmental laws and regulations, and have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or interpretations thereof could have a significant impact on us, as well as the oil and natural gas industry in general.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

The Comprehensive Environmental, Response, Compensation, and Liability Act, or CERCLA, and comparable state statutes impose strict, joint and several liability on owners and operators of sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at such sites. It is not uncommon for the government to file claims requiring cleanup actions, demands for reimbursement for government-incurred cleanup costs, or natural resource damages, or for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. The Federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes govern the disposal of "solid waste" and "hazardous waste" and authorize the imposition of substantial fines and penalties for noncompliance, as well as requirements for corrective actions. Although CERCLA currently excludes petroleum from its definition of "hazardous substance," state laws affecting our operations may impose clean-up liability relating to petroleum and petroleum-related products. In addition, although RCRA classifies certain oil field wastes as "non-hazardous," such exploration and production wastes could be reclassified as hazardous wastes thereby making such wastes subject to more stringent handling and disposal requirements. CERCLA, RCRA and comparable state statutes can impose liability for clean-up of sites and disposal of substances found on drilling and production sites long after operations on such sites have been completed. Other statutes relating to the storage and handling of pollutants include the Oil Pollution Act of 1990, or OPA, which requires certain owners and operators of facilities that store or otherwise handle oil to prepare and implement spill response plans relating to the potential discharge of oil into surface waters. The OPA contains numerous requirements relating to prevention of, reporting of, and response to oil spills into waters of the United States. State laws mandate oil cleanup programs with respect to contaminated soil. A failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions.

The Endangered Species Act, or ESA, seeks to ensure that activities do not jeopardize endangered or threatened animal, fish and plant species, or destroy or modify the critical habitat of such species. Under the ESA, exploration and production operations, as well as actions by federal agencies, may not significantly impair or jeopardize the species or its habitat. The ESA has been used to prevent or delay drilling activities and provides for criminal penalties for willful violations of its provisions. Other statutes that provide protection to animal and plant species and that may apply to our operations include, without limitation, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act, and the Bald and Golden Eagle Protection Act. Although we believe that our operations are in substantial compliance with these statutes, any change in these statutes or any reclassification of a species as threatened or endangered or re-determination of the extent of "critical habit" could subject us to significant expenses to modify our operations or could force us to discontinue some operations altogether.

The National Environmental Policy Act, or NEPA, requires a thorough review of the environmental impacts of "major federal actions" and a determination of whether proposed actions on federal and certain Indian lands would result in "significant impact" on the environment. For purposes of NEPA, "major federal action" can be something as basic as issuance of a required permit. For oil and gas operations on federal and certain Indian lands or requiring federal permits, NEPA review can increase the time for obtaining approval and impose additional regulatory burdens on the natural gas and oil industry, thereby increasing our costs of doing business and our profitability.

The Clean Water Act, or CWA, and comparable state statutes, impose restrictions and controls on the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the Environmental Protection Agency (EPA) or an analogous state agency. The CWA regulates storm water run-off from oil and natural gas facilities and requires a storm water discharge permit for certain activities. Such a permit requires the regulated facility to monitor and sample storm water run-off from its operations. The CWA and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release.

The Safe Drinking Water Act, or SDWA, and the Underground Injection Control (UIC) program promulgated thereunder, regulate the drilling and operation of subsurface injection wells. EPA directly administers the UIC program in some states and in others the responsibility for the program has been delegated to the state. The program requires that a permit be obtained before drilling a disposal well. Violation of these regulations and/or contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SWDA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury.

Our operations employ hydraulic fracturing techniques to stimulate natural gas production from unconventional geological formations, which entails the injection of pressurized fracturing fluids into a well bore. The federal Energy Policy Act of 2005 amended the SDWA to exclude hydraulic fracturing from the definition of "underground injection" under certain circumstances. However, the repeal of this exclusion has been advocated by certain advocacy organizations and others in the public. Legislation to amend the SDWA to repeal this exemption and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, was introduced during the previous session of Congress and may be reintroduced during the current session of Congress. In addition, the EPA at the request of Congress is currently conducting a national study examining the potential impacts of hydraulic fracturing on drinking water resources, with a draft of the final report expected to be released in 2014.

On May 11, 2012, the BLM published proposed rules to regulate hydraulic fracturing on federal public lands and Indian lands. The proposed rules would address well stimulation operations, including requiring agency approval for certain activities, and would require the disclosure of well stimulation fluids, as well as address issues relating to flowback water. The rules are expected to be finalized in the first half of 2013. In addition, some states and localities have adopted, and others are considering adopting, regulations or ordinances that could restrict hydraulic fracturing in certain circumstances, or that would impose higher taxes, fees or royalties on natural gas production. If new federal or state laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities, make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business. It is also possible that our drilling and injection operations could adversely affect the environment, which could result in a requirement to perform investigations or clean-ups or in the incurrence of other unexpected material costs or liabilities.

The Clean Air Act, as amended, restricts the emission of air pollutants from many sources, including oil and gas operations. On April 17, 2012, the EPA issued final rules under the Clean Air Act that subject oil and natural gas production, processing, transmission and storage operations within federal regulatory jurisdiction to regulation under the New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants programs. The EPA rules include New Source Performance Standards for completions of hydraulically fractured wells. The final rules establish a phase-in period that will ensure that manufacturers have time to make and broadly distribute the required emissions reduction technology. During the first phase, until January 1, 2015, owners and operators must either flare their emissions or use emissions reduction technology called "green completions." The finalized rules also establish specific new requirements for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. In addition, on August 15, 2012, the EPA issued a final rule approving and promulgating a Federal Implementation Plan for Oil and Natural Gas Production Facilities for the Fort Berthold Indian Reservation in North Dakota under the Clean Air Act. The new rule requires oil and gas owners and operators on the Reservation to reduce emissions of volatile organic compounds from oil and natural gas well completions, recompletions, and production and storage operations. At this time, we believe we are in compliance with these regulations and do not expect them to have a material impact on our operations.

Legislation targeting air emissions from hydraulic fracturing activities was introduced during the previous session of Congress and may be reintroduced during the current session of Congress. New legislation and regulations governing emissions of air pollutants may increase the costs of compliance for some facilities or the cost of transportation or processing of produced oil and natural gas which may affect our operating costs. In addition, new facilities may be required to obtain permits before work can begin, and existing facilities may be required to incur capital costs in order to remain in compliance.

Significant studies and research have been devoted to climate change and global warming, and climate change has developed into a major political issue in the United States and globally. Certain research suggests that greenhouse gas emissions contribute to climate change and pose a threat to the environment. Recent scientific research and political debate has focused in part on carbon dioxide and methane incidental to oil and natural gas exploration and production. Many state governments have enacted legislation directed at controlling greenhouse gas emissions, and future state and federal legislation and regulation could impose additional restrictions or requirements in connection with our operations and favor use of alternative energy sources, which could increase operating costs and decrease demand for oil products. As such, our business could be materially adversely affected by domestic and international legislation targeted at controlling climate change.

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, or OSHA, and comparable state laws, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

We are subject to federal and state laws and regulations relating to preservation and protection of historical and cultural resources. Such laws include the National Historic Preservation Act, the Native American Graves Protection and

Repatriation Act, Archaeological Resources Protection Act, and the Paleontological Resources Preservation Act, and their state counterparts and similar statutes, which require certain assessments and mitigation activities if historical or cultural resources are impacted by our activities and provide for civil, criminal and administrative penalties and other sanctions for violation of their requirements.

We have acquired, and may in the future acquire, interests in properties that have been operated in the past by others and may be liable for environmental damage, including historical contamination, caused by such former operators. Additional liabilities could also arise from continuing violations or contamination not discovered during our assessment of the acquired properties.

We have not incurred, and do not currently anticipate incurring, any material capital expenditures for environmental control facilities.

We do not believe that our environmental, health and safety risks are materially different from those of comparable companies in the United States in the oil and natural gas industry. Nevertheless, there can be no assurance that such environmental, health and safety laws and regulations will not result in a curtailment of production or material increase in the cost of production, development or exploration or otherwise adversely affect our capital expenditures, financial condition and results of operations.

Employees and Office Space

Our principal executive offices are located at 1625 Broadway, Suite 250, Denver, Colorado 80202, and our telephone number is (303) 592-8075. As of December 31, 2012, we employed 102 full-time employees. None of our employees are subject to a collective bargaining agreement, and we consider our relations with our employees to be very good.

Available Information

We maintain a website at *http://www.kodiakog.com*. The information contained on or accessible through our website is not part of this Annual Report on Form 10-K. Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to reports filed or furnished pursuant to Sections 13(a) and 15(d) of the Exchange Act, are available on our website, free of charge, as soon as reasonably practicable after we electronically file such reports with, or furnish those reports to, the SEC.

We maintain a Code of Business Conduct and Ethics for Directors, Officers and Employees ("Code of Conduct"). A copy of our Code of Conduct may be found on our website in the Corporate Governance section. Our Code of Conduct contains information regarding whistleblower procedures.

ITEM 1A. RISK FACTORS

RISK FACTORS

An investment in our common stock involves a high degree of risk. In addition to the other information included in this Annual Report on Form 10-K, you should carefully consider each of the risks described below before purchasing shares of our common stock. The risk factors set forth below are not the only risks that may affect our business. Our business could also be affected by additional risks not currently known to us or that we currently deem to be immaterial. If any of the following risks actually occur, our business, financial condition and results of operations could materially suffer. As a result, the trading price of our common stock could decline, and you may lose all or part of your investment.

Risks Related to Kodiak

To successfully execute our development program and pay our debt service obligations and other contractual obligations, we are dependent on cash generated from anticipated production, our credit facility and, if necessary, continued access to capital markets, any or all of which may not be available in sufficient amounts.

We are dependent on achieving projected levels of cash flows from production, the continued availability of our credit facility and, if necessary, continued access to capital markets to successfully execute our operating strategies and pay our debt service obligations and other contractual obligations. As part of our cash management strategy, we frequently use available funds to reduce any balance on our credit facility. Because of this, we generally maintain low cash and cash equivalent balances. As a result, since our principal source of operating cash flows (proved reserves to be produced in future years) is not considered working capital, we often have low or negative working capital. There can be no assurance that we will achieve anticipated future cash flows from production, that credit will be available under our credit facility when needed or that we will be able to complete transactions in the capital markets, if needed. Our ability to obtain financing on commercially reasonable terms is dependent on a number of factors, many of which we cannot control, including changes in our credit rating, interest rates, market perceptions of us and the oil and natural gas exploration and production industry and tax burdens due to new tax laws. If we were not successful in obtaining sufficient funding or completing an alternative transaction on a timely basis on terms acceptable to us, we would be required to curtail our planned expenditures or restructure our operations (including reducing our rig count and sub-contracting our pressure pumping services agreement, either of which may result in termination fees depending on the timing and requirements of the underlying agreements), we would be unable to implement our original exploration and drilling program, and we may be unable to service our debt obligation or satisfy our contractual obligations. Any such consequences could have a material adverse effect on our business, financial condition and results of operation.

Part of our strategy involves drilling in existing or emerging shale plays using some of the latest available horizontal drilling and completion techniques. The results of our planned exploratory and development drilling in these plays are subject to drilling and completion technique risks and drilling results may not meet our expectations for reserves or production. As a result, we may incur material write-downs and the value of our undeveloped acreage could decline if drilling results are unsuccessful.

Operations in the Bakken involve utilizing some of the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling include, but are not limited to, landing our wellbore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the wellbore and being able to run tools and other equipment consistently through the horizontal wellbore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the wellbore and successfully cleaning out the wellbore after completion of the final fracture stimulation stage.

Our experience with horizontal drilling utilizing the latest drilling and completion techniques specifically in the Bakken is limited to the time since our operations began in 2008. Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and limited takeaway capacity or otherwise, and/or natural gas and oil prices decline, the return on our investment in these areas may not be as attractive as we anticipate and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Substantially all of our producing properties and operations are located in the Williston Basin region, making us vulnerable to risks associated with operating in one major geographic area.

As of December 31, 2012, substantially all of our estimated proved reserves and production were generated in the Williston Basin in northwestern North Dakota and northeastern Montana. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of oil or natural gas produced from the wells in this area. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and gas producing areas such as the Williston Basin, which may cause these conditions to occur with greater frequency or magnify the effect of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

Our substantial indebtedness, which may increase in the future, reduces our financial and operating flexibility.

As of December 31, 2012, we had $295.0 million of secured indebtedness, $805.6 million of senior indebtedness and no subordinated indebtedness. As of the date of this filing, we have $1.16 billion of senior indebtedness, no subordinated indebtedness, $50.0 million secured indebtedness, and borrowing capacity available under our credit facility of $400.0 million. In addition, we and our subsidiaries may incur substantial additional indebtedness in the future. Our credit facility provides for a $750.0 million credit facility and our current borrowing base thereunder is $450.0 million. In addition, the indentures governing our Senior Notes allow us to issue additional notes under certain circumstances, which notes would also be guaranteed by the guarantors. Such indentures allow us to incur certain other additional secured debt and allow our subsidiaries that do not guarantee the notes to incur additional debt, which would be structurally senior to the notes. If new debt or other liabilities are added to our current debt levels, the related risks that we and our subsidiaries now face would increase.

A high level of indebtedness subjects us to a number of adverse risks. In particular, a high level of indebtedness may make it more likely that a reduction in the borrowing base of our credit facility following a periodic redetermination could require us to repay a portion of outstanding borrowings, may impair our ability to obtain additional financing in the future, and increases the risk that we may default on our debt obligations. In addition, we must devote a significant portion of our cash flows to service our debt, and we are subject to interest rate risk under our credit facility, which bears interest at a variable rate. Any increase in our interest rates could have an adverse impact on our financial condition, results of operations and growth prospects.

Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. If we do not have sufficient funds on hand to pay our debt when due, we may be required to seek a waiver or amendment from our lenders, refinance our indebtedness, incur additional indebtedness, sell assets or sell additional shares of securities. We may not be able to complete such transactions on terms acceptable to us, or at all. Our failure to generate sufficient funds to pay our debts or to undertake any of these actions successfully could result in a default on our debt obligations, which would materially adversely affect our business, results of operations and financial condition.

Our credit facility and the indentures governing our Senior Notes contain operating and financial restrictions that may restrict our business and financing activities.

Our credit facility and the indentures governing our Senior Notes contain (and any future indebtedness we incur may contain) a number of restrictive covenants that impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things, make investments, incur additional indebtedness or issue preferred stock, consolidate, merge or sell assets, make distributions on capital stock or prepay subordinated indebtedness and create unrestricted subsidiaries. As a result of these covenants, we are and will continue to 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 credit facility and the aforementioned indentures 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 credit facility or any future indebtedness could result in an event of default under the agreements governing our indebtedness, which, if not cured or waived, could have a material adverse affect on our business, financial condition and results of operations. If an event of default under our 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; and
- may prevent us from making debt service payments under our other agreements.

A payment default or an acceleration under our credit facility could result in an event of default and an acceleration under the aforementioned indentures. If the indebtedness under our Senior 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 the credit facility are collateralized by perfected first priority liens and security interests on substantially all of our assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports, and if we are unable to repay our indebtedness under the credit facility, the lenders could seek to foreclose on our assets.

Servicing our debt requires a significant amount of cash, which we may not have available when payments are due, and our ability to service our debt is largely dependent on our receipt of distributions or other payments from our subsidiary.

Our ability to make scheduled payments of the principal of, to pay interest on or to refinance our indebtedness, including the notes, will depend upon our future operating performance, which is subject to general economic and competitive conditions and to financial, business and other factors, many of which we cannot control. In addition, because we are a holding company, our ability to service our debt is largely dependent on the earnings of our subsidiary and the payment of those earnings to us in the form of dividends, loans or advances and through repayment of loans or advances from us. Our subsidiary is legally distinct from us and has no obligation to make funds available to us for such payment. The ability of our subsidiary to pay dividends, repay intercompany notes or make other advances to us is subject to restrictions imposed by applicable laws, tax considerations and the agreements governing our subsidiary. In addition, such payment may be restricted by claims against our subsidiary by its creditors, including suppliers, vendors, lessors and employees.

The availability of borrowings under our credit facility is based on a borrowing base, which is subject to semi-annual redetermination by our lenders based on their valuation of our proved reserves and the lenders' internal criteria. In the event the amount outstanding under our credit facility at any time exceeds the borrowing base at such time, we may be required to repay a portion of our outstanding borrowings on an accelerated basis. In the future, we may incur additional indebtedness in order to make future acquisitions or to develop our properties, including under our credit facility.

If we do not have sufficient funds on hand to pay our debt, we may be required to seek a waiver or amendment from our lenders, refinance our indebtedness, sell assets or sell additional shares of securities. Our ability to refinance our indebtedness will depend on the capital markets and our financial condition at the time. We may not be able obtain such financing or complete such transactions on terms acceptable to us, or at all. In addition, we may not be able to consummate an asset sale to raise capital or sell assets at prices that we believe are fair, and proceeds that we do receive may not be adequate to meet any debt service obligations then due. Our credit facility and the indentures governing our Senior Notes restrict, but do not completely prohibit, our ability to use the proceeds from asset sales. Our failure to generate sufficient funds to pay our debts or to undertake any of these actions successfully could result in a default on our debt obligations, which would materially adversely affect our business, results of operations and financial condition.

We may not adhere to our proposed drilling schedule, and we may not be able to successfully drill wells that produce oil or natural gas in commercially viable quantities. Our drilling, completion and workover activities may affect our production.

Although we have budgeted for 75 gross (61 net) operated drilling locations for 2013, we may not be able to drill those locations within our expected time frame or at all. Our final determination of whether to drill any scheduled or budgeted wells will be dependent on a number of factors, including the availability and costs of equipment and crews, economic and industry conditions, prices for oil and gas and the availability of sufficient capital resources.

In addition, we cannot assure you that each well we do drill will produce commercial quantities of oil and natural gas. The total cost of drilling, completing and operating a well is uncertain before drilling commences. Overruns in budgeted expenditures are a common risk that can make a particular project uneconomical. 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 prior to drilling each well whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. Our use of seismic data is subject to interpretation and may not accurately identify the presence of natural gas and oil. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays and restrictions imposed by or resulting from compliance with regulatory requirements;
- changes in laws and regulations applicable to oil and natural gas activities;
- hazards resulting from unusual or unexpected geological or environmental conditions;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- land title problems;
- lack of available gathering facilities or delays in construction of gathering facilities;
- unanticipated transportation costs and delays; and
- limitations in the market for oil and natural gas.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties. The occurrence of any of these events could negatively affect our ability to successfully drill wells that produce oil or natural gas in commercially viable quantities.

To the extent that we do successfully drill wells that produce oil or natural gas, our drilling, completion and workover activities may affect the timing and amount of production from such wells.

Our commodity derivative arrangements could result in financial losses or could reduce our earnings.

We enter into financial hedge arrangements (commodity derivative agreements) in order to manage our commodity price risk and to provide a more predictable cash flow from operations. We have not and do not intend to designate our derivative instruments as hedges for accounting purposes. The fair value of our derivative instruments will be marked to market at the end of each quarter and the resulting unrealized gains or losses due to changes in the fair value of our derivative instruments will be recognized in current earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments. Under our credit facility, we may hedge up to 85% of our forecasted volumes from proved properties with collars, puts or fixed price instruments.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative contracts for such period. If the actual amount of production is higher than we estimated, we will have greater commodity price exposure than we intended. If the actual amount of production is lower than the notional amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows. Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counter-party to the derivative instrument defaults on its contract obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- the steps we take to monitor our derivative financial instruments do not detect and prevent transactions that are inconsistent with our risk management strategies.

In addition, depending on the type of derivative arrangements we enter, the agreements could limit the benefit we would receive from increases in oil prices. We cannot assure you that the hedging transactions we have entered into, or will enter into, will adequately protect us from fluctuations in oil prices.

We have historically incurred losses and cannot assure investors as to future profitability.

Although we had net income for the years ended 2011 and 2012, we have historically incurred losses from operations during our history in the oil and natural gas business. While we have developed some of our properties, many of our properties are in the exploration stage, and to date we have established a limited volume of proved reserves on our properties. Our ability to be profitable in the future will depend on successfully implementing our acquisition, exploration, development and production activities, all of which are subject to many risks beyond our control. We cannot assure you that we will successfully implement our business plan or that we will achieve commercial profitability in the future. Even if we remain profitable on an annual basis, we cannot assure you that our profitability will be sustainable or increase on a periodic basis.

The actual quantities and present value of our proved reserves may be lower than we have estimated. In addition, the present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.

This annual report on Form 10-K for the year ended December 31, 2012 contains estimates of our proved oil and natural gas reserves and the estimated future net revenues from these reserves. The process of estimating oil and natural gas reserves is complex and requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Accordingly, these estimates are inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, development and operating expenses, and quantities of recoverable oil and natural gas reserves most likely will vary from these estimates and vary over time. Such variations may be significant and could materially affect the estimated quantities and present value of our proved reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development drilling, results of secondary and tertiary recovery applications, prevailing oil and natural gas prices and other factors, many of which are beyond our control. You should also not assume that our initial rates of production of our wells will lead to greater overall production over the life of the wells, or that early results suggesting lack of reservoir continuity will prove to be accurate.

You should not assume that the present value of future net revenues referred to in this annual report is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on the un-weighted average of the closing prices during the first day of each of the twelve months preceding the end of the fiscal year. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any change in consumption by oil or natural gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of our oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor nor does it reflect discount factors used in the market place for the purchase and sale of oil and natural gas.

Our reserves and production will decline, and unless we replace our oil and natural gas reserves, our business, financial condition and results of operations will be adversely affected.

Producing oil and natural gas reserves ultimately results in declining production that will vary depending on reservoir characteristics and other factors. Thus, our future oil and natural gas production and resulting cash flow and earnings are directly dependent upon our success in developing our current reserves and finding 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.

Properties that we have acquired and that we may acquire in the future may not produce oil or natural gas as projected, and we may be unable to successfully determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them, which could cause us to incur losses.

One of our growth strategies is to pursue selective acquisitions of undeveloped leasehold oil and natural gas reserves. When we choose to pursue an acquisition, we perform an informal review of the target properties that we believe is consistent with industry practices. However, these informal reviews are inherently incomplete. Generally, it is not feasible to review in depth every individual property involved in each acquisition, and we have generally not done so in connection with our historical acquisitions. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and potential. We may not perform, and in connection with our historical acquisitions have generally not performed, an inspection on every well. Environmental problems, such as subsurface or groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even if problems are identified, we may not be able to obtain effective contractual protection against all or part of those problems, and we often may assume environmental and other risks and liabilities in connection with the acquired properties, as has generally been the case with respect to properties acquired to date.

Our business involves numerous operating hazards and exposure to significant weather and climate risks. We have not insured and cannot fully insure against all risks related to our operations, which could result in substantial claims for which we are underinsured or uninsured.

We have not insured and cannot fully insure against all risks and have not attempted to insure fully against risks where the cost of available coverage is excessive relative to the perceived risks presented. In addition, certain pollution and environmental risks generally are not insurable. Our exploration, drilling and other activities are subject to risks such as:

- adverse weather conditions, natural disasters and other environmental disturbances;
- fires and explosions;
- theft or vandalism of oilfield equipment and supplies, especially in areas of increased activity;
- environmental hazards, such as uncontrollable flows of natural gas, oil, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- equipment malfunctions and/or mechanical failure on high-volume wells;
- personal injuries and death, including insufficient worker compensation coverage for third-party contractors who provide drilling services; and
- security breaches or terroristic acts.

In particular, our operations in North Dakota, Montana and Wyoming are conducted in areas subject to extreme weather conditions and often in difficult terrain. Primarily in the winter and spring, our operations are often curtailed because of cold, snow and wet conditions. Unusually severe weather could further curtail these operations, including drilling of new wells or production from existing wells, and depending on the severity of the weather, could have a material adverse effect on our business, financial condition and results of operations. In addition, weather conditions and other events could temporarily impair our ability to transport our oil and natural gas production.

As is customary with industry practice, operators generally indemnify drilling contractors and oilfield service companies (collectively, contractors) against certain losses suffered by the operator and third parties resulting from a well blowout or fire or other uncontrolled flow of hydrocarbons, regardless of the relative fault of the contractor.

We do not carry business interruption insurance coverage. Losses and liabilities arising from uninsured and underinsured events, which could arise from even one catastrophic accident, could reduce the funds available for our exploration, development and production activities and could materially and adversely affect our business, results of operations and financial condition.

We have limited control over activities in properties we do not operate, which could reduce our production and revenues, affect the timing and amounts of capital requirements and potentially result in a dilution of our respective ownership interest in the event we are unable to make any required capital contributions.

We do not operate all of the properties in which we have an interest. As a result, we may have a limited ability to exercise influence over normal operating procedures, expenditures or future development of underlying properties and their associated costs. For all of the properties that are operated by others, we are dependent on their decision-making with respect to day-to-day operations over which we have little control. The failure of an operator of wells in which we have an interest to adequately perform operations, or an operator's breach of applicable agreements, could reduce production and revenues we receive from that well. The success and timing of our drilling and development activities on properties operated by others depend upon a number of factors outside of our control, including the timing and amount of capital expenditures, the available expertise and financial resources, the inclusion of other participants and the use of technology. Since we do not own the majority interest in many of the wells we do not operate, we may not be in a position to remove the operator in the event of poor performance.

In particular, we are party to a joint venture agreement with a third party that relates to the development of certain of our properties in Dunn County, North Dakota. Pursuant to this agreement, we are required to pay 50% of the drilling expenses attributable to our joint venture's proportionate interest incurred in the area of mutual interest. If the expenses associated with our joint venture partner's exploration activity exceed our current expectations or if our joint venture partner mobilizes additional drilling rigs in the future, we may be required to make significantly higher capital contributions to satisfy our proportionate share of the exploration costs. If such capital contributions are required, we may not be able to obtain the financing necessary to satisfy our obligations or we may have to reallocate our anticipated capital expenditure budget. In the event that we do not participate in future capital contributions with respect to this joint venture agreement or any other agreements relating to properties we do not operate, our respective ownership interest could be diluted.

We depend on a limited number of purchasers for sales of our oil and natural gas. We are exposed to credit risk if one or more of our significant purchasers becomes insolvent and fails to pay amounts owed to us.

For the year ended December 31, 2012, approximately 60% of our oil and natural gas revenues were from three purchasers. It is possible that one or more of our purchasers will become financially distressed and default on their obligations to us. Furthermore, bankruptcy of one or more of our purchasers, or some other similar procedure, might make it difficult for us to collect all or a significant portion of amounts owed by the purchasers. Our inability to collect our accounts receivable could have a material adverse effect on our results of operations.

The concentration of credit risk in a single industry affects our overall exposure to credit risk because purchasers may be similarly affected by changes in economic and other conditions. Although we have not been directly affected, we are aware that some refiners have filed for bankruptcy protection, which has caused the affected producers to not receive payment for the production that was delivered. If economic conditions deteriorate, it is likely that additional, similar situations will occur which will expose us to added risk of not being paid for oil or natural gas that we deliver. We do not obtain credit protections such as letters of credit, guarantees or prepayments from our purchasers. We are unable to predict what impact the financial difficulties of any of our purchasers may have on our future results of operations and liquidity.

Our interests are held in the form of leases that we may be unable to retain and the title to our properties may be defective.

Our properties are held under leases and working interests in leases. Generally, the leases we are a party to provide for a fixed term, but contain a provision that allows us to extend the term of the lease so long as we are producing oil or natural gas in quantities to meet the required payments under the lease. If we or the holder of a lease fails to meet the specific requirements of the lease regarding delay rental payments, continuous production or development, or similar terms, portions of the lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each lease will be met. The termination or expiration of our leases or the working interests relating to leases may reduce our opportunity to exploit a given prospect for oil and natural gas production and thus have a material adverse effect on our business, results of operation and financial condition.

It is our practice in acquiring interests in oil and natural gas leases not to undergo the expense of retaining lawyers to fully examine the title to the interest to be placed under lease or already placed under lease. Rather, we rely upon the judgment of oil and natural gas lease brokers or landmen who actually do the field work in examining records in the appropriate governmental office before attempting to place under lease a specific interest. We believe that this practice is widely followed in the oil and natural gas industry.

Prior to drilling a well for oil and natural gas, it is the normal practice in the oil and natural gas industry for the person or company acting as the operator of the well to hire a lawyer to examine the title to the unit within which the proposed oil and natural gas well is to be drilled. Frequently, as a result of such examination, curative work must be done to correct deficiencies in the marketability of the title. The work entails expense and might include obtaining an affidavit of heirship or causing an estate to be administered. The examination made by the title lawyers may reveal that the oil and natural gas lease or leases are worthless, having been purchased in error from a person who is not the owner of the mineral interest desired. In such instances, the amount paid for such oil and natural gas lease or leases may be lost.

Our significant inventory of undeveloped acreage and large percentage of undeveloped proved reserves may create additional economic risk.

Our success is largely dependent upon our ability to develop our significant inventory of future drilling locations, undeveloped acreage and undeveloped reserves. As of December 31, 2012, approximately 54% of our total proved reserves were undeveloped. To the extent our drilling results are not as successful as we anticipate, natural gas and oil prices decline, or sufficient funds are not available to drill these locations and reserves, we may not capture the expected or projected value of these properties. In addition, delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic.

We depend on our key management personnel and technical experts and the loss any of these individuals could adversely affect our business.

If we lose the services of our key management personnel, technical experts or are unable to attract additional qualified personnel, our business, financial condition, results of operations, development efforts and ability to grow could suffer. We have assembled a team of engineers and geologists who have considerable experience in applying advanced horizontal drilling and completion technology to explore for and to develop oil and natural gas. We depend upon the knowledge, skill and experience of these experts to assist us in improving the performance and reducing the risks associated with our participation in oil and natural gas exploration and development projects. In addition, the success of our business depends, to a significant extent, upon the abilities and continued efforts of our management.

The sale of our oil and natural gas production depends in part on gathering, transportation and processing facilities. Any limitation in the availability of, or our access to, those facilities would interfere with our ability to market the oil and natural gas that we produce and could adversely impact our drilling program, cash flows and results of operations.

We deliver oil and natural gas through gathering, processing and pipeline systems that we do not own. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. In particular, natural gas produced in the Bakken has a high Btu content that requires gas processing to remove the natural gas liquids before it can be redelivered into transmission pipelines. Industry-wide in the Williston Basin, there is currently a shortage of gas gathering and processing capacity. Such shortage has limited our ability to sell our gas production. As a result, the majority of our gas from the Bakken wells to date has been flared.

The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. Additionally, if we were prohibited from flaring natural gas due to environmental or other regulations, then we would be forced to shut-in producing wells, which would also adversely impact our drilling program. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities or any changes in regulatory requirements affecting flaring activities, could harm our business and, in turn, our financial condition, results of operations and cash flows.

Operations on the Fort Berthold Indian Reservation of the Three Affiliated Tribes in North Dakota are subject to various federal and tribal regulations and laws, any of which may increase our costs and delay our operations.

Various federal agencies including the Office of Natural Resources Revenue (formerly the Minerals Management Service) and the BIA, along with the Three Affiliated Tribes, promulgate and enforce regulations pertaining to operations on the Fort Berthold Indian Reservation. In addition, the Three Affiliated Tribes is a sovereign nation having the right to enforce laws and regulations independent from federal, state and local statutes and regulations. These tribal laws and regulations include various taxes, fees and other conditions that apply to lessees, operators and contractors conducting operations on Native American tribal lands. Lessees and operators conducting operations on tribal lands are generally subject to the Native American tribal court system. One or more of these factors may increase our costs of doing business on the Fort Berthold Indian Reservation and may have an adverse impact on our ability to effectively transport products within the Fort Berthold Indian Reservation or to conduct our operations on such lands.

We may have difficulty managing our growth and the related demands on our resources, and the integration of significant acquisitions may be difficult.

In recent years, we have experienced significant growth through the expansion of our drilling program and through significant acquisitions. As a result of our growth, we may experience difficulties in finding and retaining additional qualified personnel. In an effort to meet the demands of our planned activities, we may be required to supplement our staff with contract and consulting personnel until we are able to hire new employees. In addition, our management may not be able to successfully or efficiently manage our growth and significant indebtedness. As a result, we may be unable to fully execute our plans, which could have a material adverse effect on our growth, results of operations and our ability to pay amounts owed in respect of our long term indebtedness.

We periodically evaluate potential acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions, any of which acquisitions would likely result in additional growth and strains on our resources. Successful acquisitions require an assessment of numerous factors, and the accuracy of these assessments is inherently uncertain. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis, and if we are entitled to environmental indemnification, we often are entitled to only limited indemnification. Significant acquisitions and other strategic transactions may involve other risks, including diversion of our management's attention, challenge and cost of integrating acquired operations and failure to realize the full benefit that we expect. The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

Risks Relating to Our Industry

Oil and natural gas prices are volatile. A substantial or extended decline in oil prices, an expansion in the differential between market prices and the price we receive and, to a lesser extent, a decrease in natural gas prices, could adversely affect our financial position, financial results, cash flows, access to capital and ability to grow.

Historically, the markets for natural gas and oil have been volatile and they are likely to continue to be volatile. As with most other companies involved in resource exploration and development, we may be adversely affected by future increases in the costs of conducting exploration, development and resource extraction that may not be fully offset by increases in the price received on sales of oil or natural gas. Our focus on exploration activities therefore exposes us to greater risks than are generally encountered in later-stage oil and natural gas property development companies.

The economic success of any drilling project will depend on numerous factors, including:

- our ability to drill, complete and operate wells;
- our ability to estimate the volumes of recoverable reserves relating to individual projects;
- rates of future production;
- future commodity prices received; and
- investment and operating costs and possible environmental liabilities.

Wide fluctuations in natural gas and oil prices may result from relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and other factors that are beyond our control. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices a producer may expect and its level of production depend on numerous factors beyond its control, such as:

- worldwide and domestic supplies of natural gas and oil;
- weather conditions;
- the level of consumer demand;
- the price and availability of alternative fuels;
- technological advances affecting energy consumption;
- the proximity and capacity of natural gas pipelines and other transportation facilities;
- the price and level of foreign imports;
- domestic and foreign governmental regulations and taxes;
- the nature and extent of regulation relating to carbon dioxide and other greenhouse gas emissions;
- the actions of the Organization of Petroleum Exporting Countries;
- political instability or armed conflict in oil-producing regions; and
- overall domestic and global economic conditions.

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties in an acquisition and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Lower oil and natural gas prices may not only decrease revenues on a per unit basis, but also may reduce the amount of oil and natural gas that can be economically produced. Lower prices will also negatively affect the value of proved reserves.

Our revenues, operating results, profitability and future rate of growth depend primarily upon the prices we receive for oil and, to a lesser extent, natural gas, that we sell. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. A reduction in oil and gas prices may result in a decrease in the borrowing base or maximum credit available to us under our credit facility. In addition, we may need to record asset carrying value write-downs if prices fall, as was the case in 2008 and 2007.

To attempt to reduce our price risk, we have implemented a strategy to hedge a portion of our expected future production. We cannot assure you that such transactions will reduce the risk or minimize the effect of any decline in oil or natural gas prices. Any substantial or extended decline in the prices of or demand for oil would have a material adverse effect on our financial condition and results of operations and could adversely affect our financial position, financial results, cash flows, access to capital and ability to grow.

Lower oil and natural gas prices may cause us to record ceiling test write-downs.

We use the full cost method of accounting to account for our oil and natural gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop oil and natural gas properties. Under full cost accounting rules, the net capitalized costs of oil and natural gas properties may not exceed a "full cost ceiling" which is based upon the present value of estimated future net cash flows from proved reserves, including the effect of hedges in place, discounted at 10%, plus the lower of cost or fair market value of unproved properties. If at the end of any fiscal period we determine that the net capitalized costs of oil and natural gas properties exceed the full cost ceiling, we must charge the amount of the excess to earnings in the period then ended. This is called a "ceiling test write-down." This charge does not impact cash flow from operating activities, but does reduce our net income and stockholders' equity. While we did not recognize any ceiling test write-downs for the year ended December 31, 2012, we may recognize write-downs in the future if commodity prices continue to decline or if we experience substantial downward adjustments to our estimated proved reserves.

Conducting operations in the oil and natural gas industry subjects us to complex laws and regulations that can have a material adverse effect on the cost, manner and feasibility of doing business.

Companies that explore for and develop, produce and sell oil and natural gas in the United States are subject to extensive federal, state, local and tribal laws and regulations, including complex tax and environmental laws and the corresponding regulations, and are required to obtain various permits and approvals from federal, state, local and tribal agencies and authorities. Our ability to obtain, sustain and renew these permits on acceptable terms and without unfavorable restrictions or conditions is subject to a change in regulations and policies and to the discretion of the applicable governmental agencies or authorities, among other factors. Our inability to obtain, or our loss of or denial of extensions of, any of these permits could limit our ability to conduct our operations as planned. In addition, we may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

- drilling permits, bonds and reports concerning operations;
- drilling and casing wells, plugging and abandoning wells and reclamation and restoration of properties;
- well stimulation processes;
- air and water quality, water discharge and disposal, and noise levels;
- location and spacing of wells, unitization and pooling of properties;
- rights-of-way and easements;
- gathering, storage, transportation and marketing of oil and natural gas;
- reclamation and remediation, environmental protection, and habitat and endangered species protection;
- safety precautions;
- taxation; and
- waste transport and disposal.

Failure to comply with these laws and regulations may result in the suspension or termination of operations and subject us to liabilities and administrative, civil and criminal penalties. Compliance costs can be significant. Moreover, these laws and regulations could change in ways that substantially increase the costs of doing business. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our business, financial condition and results of operations.

Developments in the global financial system may have impacts on our liquidity and financial condition that we currently cannot predict.

Global financial markets may have a material adverse impact on our business and our financial condition, and we may face challenges if conditions in the financial markets are inadequate to finance our activities at a reasonable cost of capital. There continues to be concern over the worldwide economic outlook, geopolitical issues, the availability and costs of credit, the negative impact on economic growth resulting from the combination of federal income tax increases and government spending restrictions which occurred at the end of the calendar year 2012 in the U.S. and the sovereign debt crisis, all of which have contributed to increased volatility in the global financial markets and commodity prices and diminished expectations for the global economy. We are unable to predict the duration or severity of the current economic situation or its impact on our business. As a result, our ability to access the capital markets or borrow money may be restricted or made more expensive at a time when we would like, or need, to raise capital, which could have an adverse impact on our flexibility to react to changing economic and business conditions and on our ability to fund our operations and capital expenditures in the future. The economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us, and on the liquidity of our operating partners, resulting in delays in operations or their failure to make required payments. Also, market conditions could have an impact on our natural gas and oil derivatives transactions if our counterparties are unable to perform their obligations or seek bankruptcy protection. Additionally, developments in the global financial system could lead to further reductions in the demand for natural gas and oil, or further reductions in the prices of natural gas and oil, or both, which could have a negative impact on our financial position, results of operations and cash flows. While the ultimate outcome and impact of the current financial situation cannot be predicted, it may have a material adverse effect on our future liquidity, results of operations and financial condition.

Our operations are subject to environmental, health and safety, and historic preservation laws and regulations that may expose us to significant costs and liabilities.

Our oil and natural gas exploration and production operations are subject to stringent and complex federal, state, local and tribal laws and regulations governing environmental protection, health and safety and historic preservation. These laws and regulations include, but are not limited to, the Clean Air Act, CWA, OPA, RCRA, CERCLA, SDWA, ESA, NEPA, OSHA, the National Historic Preservation Act, and the Native American Graves Protection and Repatriation Act, and their state counterparts and similar statutes, which provide for civil, criminal and administrative penalties and other sanctions for violation of their requirements. These laws and regulations impose numerous obligations on us and our operations. Several governmental authorities, such as the EPA, the BIA, the BLM and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued thereunder. The interpretation and enforcement of these laws, regulations and permits has tended to become more stringent over time. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil or criminal penalties; the imposition of investigatory, remedial or monitoring obligations; and the issuance of injunctions limiting or prohibiting some or all of our operations.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations because of our handling of petroleum hydrocarbons and wastes, air emissions and wastewater discharges related to our operations, our ownership and operation of real property, including acquired properties, and historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to strict, joint and several liability for the removal or remediation of contamination at properties we currently own, lease or operate or have owned, leased or operated in the past or to which we have sent waste. These laws often impose liability even if the owner, lessee or operator was not responsible for the contamination or the contamination resulted from actions taken in compliance with all applicable laws in effect at the time. Private parties, including the owners of properties upon which our wells are drilled or where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, may bring claims against us for property damage or personal injury, including as a result of exposure to hazardous materials, or to enforce compliance with, or seek damages under, applicable environmental laws and regulations. In addition, the risk of accidental spills or releases could expose us to significant liabilities that could have a material adverse effect on our financial condition or results of operations. Changes in environmental laws and regulations occur frequently, and such changes could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on the results of our operations and our competitive position or financial condition. We may not be able to recover some or any of these costs from insurance or other relevant third parties.

The regulations of "over-the-counter" derivatives introduced by the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") could adversely impact our hedging strategy.

Through its comprehensive new regulatory regime for derivatives, the Dodd-Frank Act imposes mandatory clearing, exchange-trading and margin requirements on many derivatives transactions (including formerly unregulated over-the-counter derivatives) in which we may engage. The Dodd-Frank Act also creates new categories of regulated market participants who will be subject to significant new capital, registration, recordkeeping, reporting, disclosure, business conduct and other regulatory requirements. While the Commodity Futures Trading Commission, or CFTC, and other federal agencies have adopted, and continue to adopt, numerous regulations pursuant to the Dodd-Frank Act, many of the key concepts and defined terms under the Dodd-Frank 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 Dodd-Frank Act and the regulations promulgated thereunder may have on our hedging activities.

Whether and to what extent we will be subject to the rules and regulations promulgated under the Dodd-Frank Act will depend on the final rules and definitions adopted by the CFTC and other regulators. The possible effect of the Dodd-Frank Act could be to increase our overall costs of entering into derivatives transactions. In particular, on November 18, 2011 the CFTC published final rules under the Dodd-Frank Act establishing position limits for certain, energy commodity futures and options contracts and economically equivalent swaps, futures and options. The position limit levels set the maximum amount of covered contracts that a trader may own or control separately or in combination, net long or short. The final rules also contain limited exemptions from position limits which will be phased in over time for certain bona fide hedging transactions and positions that were established in good faith before the initial limits become effective. The final rules have been subject to legal challenge. Thus, the timing of implementation of the final rules on position limits, their applicability to, and impact on us and the success of any legal challenge to their validity remain uncertain, and there can be no assurance that they will not have a material adverse impact on us by affecting the prices of or market for commodities relevant to our operations and/or reducing the availability to us of commodity derivatives. Further, new margin requirements and capital charges, even if not directly applicable to us, may cause an increase in the pricing of derivatives transactions sold by market participants to whom such requirements apply. Administrative costs, due to new requirements such as registration, recordkeeping, reporting, and compliance, even if not directly applicable to us, may also be reflected in higher pricing of derivatives. New exchange-trading and trade reporting requirements may lead to reductions in the liquidity of derivative transactions, causing higher pricing or reduced availability of derivatives, adversely affecting the performance of our hedging strategies. Additionally, the financial counterparties to our derivative instruments may be required to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

The Dodd-Frank Act could result in the cost of executing our hedging strategy increasing significantly, which could potentially result in an undesirable decrease in the amount of oil production we hedge. If our hedging costs increase and we are required to post cash collateral, our business would be adversely affected as a result of reduced cash flow and reduced liquidity. Additionally, in the event that we hedge lower quantities in response to higher hedging costs and increased margin requirements, our exposure to changes in commodity prices would increase, which could result in decreased cash flows.

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

Hydraulic fracturing is a common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into rock formations to fracture the surrounding rock and stimulate production. There has been increasing public controversy regarding hydraulic fracturing with regard to use of fracturing fluids, impacts on drinking water supplies, use of waters, and the potential for impacts to surface water, groundwater, air quality and the environment generally. A number of lawsuits and enforcement actions have been initiated implicating hydraulic fracturing practices. Additional legislation or regulation could make it more difficult to perform hydraulic fracturing, cause operational delays, increase our operating costs or make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings. New legislation or regulations in the future could have the effect of prohibiting the use of hydraulic fracturing, which would prevent us from completing our wells as planned and would have a material adverse effect on production from our wells. If these legislative and regulatory initiatives cause a material delay or decrease in our drilling or hydraulic fracturing activities, our business and profitability could be materially impacted.

Changes in tax laws may impair our results of operations.

The current administration's proposed budget for the 2013 fiscal year and recently proposed legislation would, if enacted, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production activities, (iv) the repeal of the passive loss exception for working interests in oil and gas properties and (v) an extension of the amortization period for certain geological and geophysical expenditures. It is not possible at this time to predict how legislation or new regulations that may be adopted to address these proposals would impact our business, but any such future laws and regulations could adversely affect the amount of our taxable income or loss.

Possible regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and gas.

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, governments have begun adopting domestic and international climate change regulations that require reporting and reductions of the emission of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a by-product of the burning of oil, natural gas and refined petroleum products, are considered greenhouse gases. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs or have begun considering adopting greenhouse gas regulatory programs. At the federal level, Congress has considered legislation that could establish a cap and trade system for restricting greenhouse gas emissions in the United States. The ultimate outcome of this federal legislative initiative remains uncertain.

In addition to pending climate legislation, the EPA has issued greenhouse gas monitoring and reporting regulations. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding that greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as a first step to issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities. Moreover, the EPA has begun regulating greenhouse gas emission from certain facilities pursuant to the Prevention of Significant Deterioration and Title V provisions of the Clean Air Act.

In the courts, several decisions have been issued that may increase the risk of claims being filed by government entities and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any existing or future laws or regulations that restrict or reduce emissions of greenhouse gases could require us to incur increased operating and compliance costs. In addition, such laws and regulations may adversely affect demand for the fossil fuels we produce, including by increasing the cost of combusting fossil fuels and by creating incentives for the use of alternative fuels and energy.

The oil and natural gas industry is subject to significant competition, which may adversely affect our ability to compete.

Oil and natural gas exploration is intensely competitive and involves a high degree of risk. In our efforts to acquire oil and natural gas producing properties, we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also conduct refining and petroleum marketing operations on a worldwide basis. Their competitive advantages may negatively impact our ability to acquire prospective properties, develop reserves, attract and retain quality personnel and raise capital. Their competitive advantages may also better enable our competitors to sustain the impact of higher exploration and production costs, oil and natural gas price volatility, productivity variances among properties, competition from alternative fuel sources and technologies, overall industry cycles and other factors related to our industry.

Our operations and demand for our products are affected by seasonal factors, which may lead to fluctuations in our operating results.

Our operating results are likely to vary due to seasonal factors. Demand for oil and natural gas products will generally increase during the winter because they are often used as heating fuels. The amount of such increased demand will depend to some extent upon the severity of winter. Because of the seasonality of our business and continuous fluctuations in the prices of our products, our operating results are likely to fluctuate from period to period.

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

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or qualified personnel. Due to our significant growth, among other things, we continue to experience a lack of resources and services. During these periods, the costs and delivery times of rigs, equipment and supplies tend to increase, in some cases substantially. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases within a geographic area. If increasing levels of exploration and production result in response to strong prices of oil and natural gas, the demand for oilfield services will likely rise, and the costs of these services will likely increase, while the quality of these services may suffer. While we currently have six drilling rigs under contract, these contracts have limited remaining tenors. Five of the contracts expire in 2013 and one expires in 2015. Thus, the future lack of availability or high cost of drilling rigs, as well as any future lack of availability or high costs of other equipment, supplies, insurance or qualified personnel, in the areas in which we operate could materially and adversely affect our business and results of operations.

Risks Relating to Our Common Stock

Future sales or other issuances of our common stock could depress the market for our common stock.

We may seek to raise additional funds through one or more public offerings of our common stock, in amounts and at prices and terms determined at the time of the offering. Any sales of large quantities of our common stock could reduce the price of our common stock, and, to the extent that we raise additional capital by issuing equity securities, our existing stockholders' ownership will be diluted.

Our common stock has experienced price and volume volatility.

The price of our common stock may be impacted by any of the following, some of which may have little or no relation to our company or industry:

- investor perception of our Company and the oil and natural gas industry, including industry trends;
- domestic and international economic and capital market conditions, including fluctuations in commodity prices;
- responses to quarter-to-quarter variations in our results of operations;
- announcements of significant acquisitions, strategic alliances, joint ventures or capital commitments by us or our competitors;
- additions or departures of key personnel;
- sales or purchases of our common stock by large stockholders or our insiders;
- accounting pronouncements or changes in accounting rules that affect our financial reporting; and
- changes in legal, tax and regulatory compliance unrelated to our performance.

In addition, the stock market in general and the market for natural gas and oil exploration companies in particular have experienced extreme price and volume fluctuations that have often been unrelated or disproportionate to the operating results or asset values of those companies. These broad market and industry factors may seriously impact the market price and trading volume of our common shares regardless of our actual operating performance.

We have not paid cash dividends on our common stock and do not anticipate paying any dividends on our common stock in the foreseeable future.

We do not anticipate paying cash dividends on our common stock in the foreseeable future. Payment of future cash dividends, if any, will be at the discretion of our board of directors and will depend on our financial condition, results of operations, contractual restrictions, capital requirements, business prospects and other factors that our board of directors considers relevant. Furthermore, our credit facility prohibit us from paying dividends with respect to our common stock. Accordingly, investors may only see a return on their investment if the value of our securities appreciates.

Our constating documents permit us to issue an unlimited number of shares without shareholder approval.

Our Articles of Continuation permit us to issue an unlimited number of shares of our common stock. Subject to the requirements of any exchange on which we may be listed, we will not be required to obtain the approval of shareholders for the issuance of additional shares of our common stock. Issuances of shares of our common stock will result in immediate dilution to existing shareholders and may have an adverse effect on the value of their shareholdings.

Sale, or the availability for sale, of substantial amounts of our common stock could adversely affect the value of our common stock.

No prediction can be made as to the effect, if any, that future sales of our common stock, or the availability of common stock for future sales, will have on the market price of our common stock. We have several stockholders that hold a significant number of shares of our common stock. Sales of substantial amounts of our common stock in the public market and the availability of shares for future sale, including by one or more of our significant stockholders or shares of our common stock issuable upon exercise of outstanding options to acquire shares of our common stock, could adversely affect the prevailing market price of our common stock. This in turn would adversely affect the fair value of the common stock and could impair our future ability to raise capital through an offering of our equity securities.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 3. LEGAL PROCEEDINGS

We have no material legal proceedings pending, and we do not know of any material proceedings contemplated by governmental authorities. There are no material proceedings to which any director, officer or any of our affiliates, any owner of record or beneficially of more than five percent of any class of our voting securities, or any associate of any such director, officer, our affiliates, or security holder, is a party adverse to us or our consolidated subsidiary or has a material interest adverse to us or our consolidated subsidiary.

ITEM 4. MINE SAFETY DISCLOSURES

These disclosures are not applicable to us.

PART II

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

Market Information

Shares of our common stock, no par value, are issued in registered form. The transfer agent for the shares is Computershare Trust Company Inc., 100 University Avenue, 9th Floor, Toronto, Ontario M5J 2Y1. Our common stock began trading on the NYSE on August 4, 2011 under the symbol "KOG". Prior to that, from June 21, 2006 through August 3, 2011, our common stock traded on the NYSE MKT. On February 27, 2013, there were 80 holders of record of our Common Stock which does not include the shareholders for whom shares are held in a nominee or street name. The following table sets forth our common stock high and low prices by quarter for 2011 and 2012.

	NYSE	
Quarter Ended	High	Low
December 31, 2012	$ 9.97	$ 8.03
September 30, 2012	$ 9.92	$ 7.50
June 30, 2012	$ 10.15	$ 6.92
March 31, 2012	$ 10.90	$ 8.58
December 31, 2011	$ 9.95	$ 3.59
September 30, 2011	$ 7.03	$ 4.37
June 30, 2011	$ 7.44	$ 4.90
March 31, 2011	$ 7.70	$ 5.44

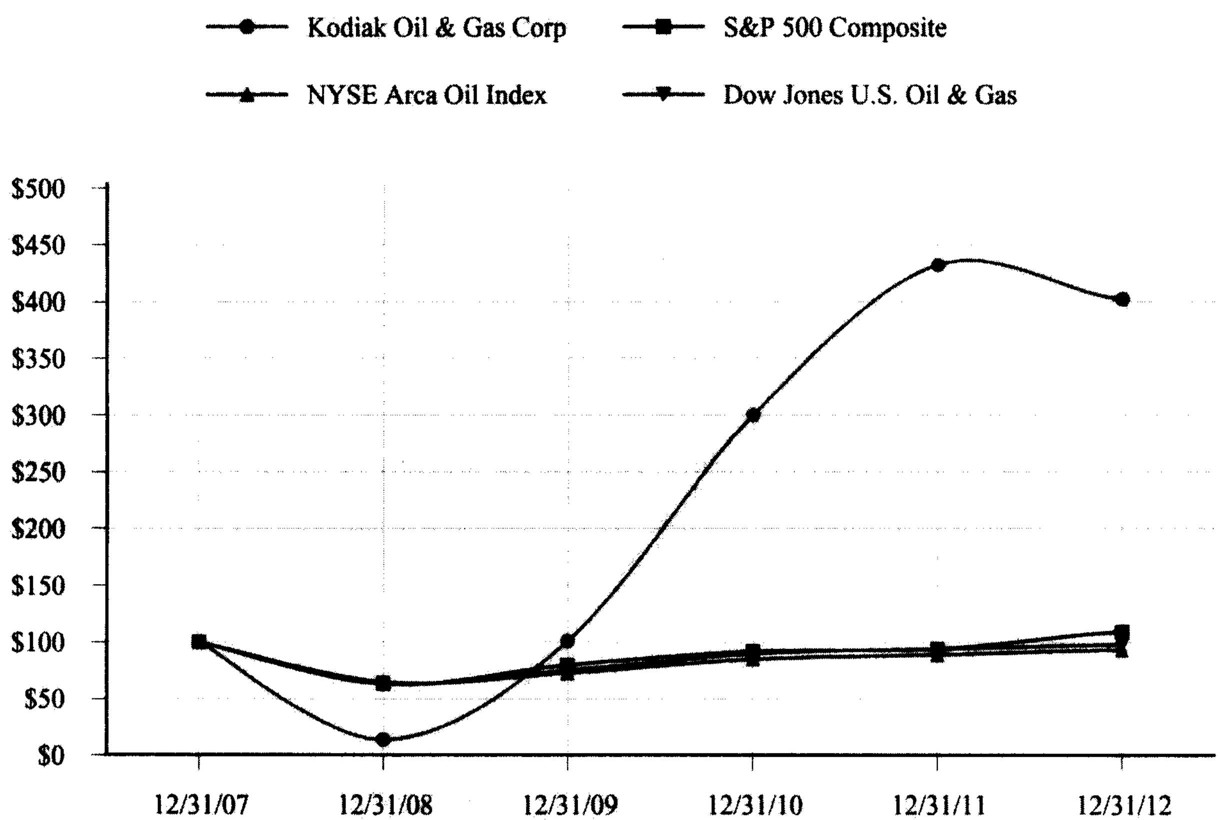
Dividend Policy

We have never paid any cash dividends on our common stock and do not anticipate paying any dividends in the foreseeable future. Our current business plan is to retain any future earnings to finance the expansion and development of our business. Any future determination to pay cash dividends will be at the discretion of our board of directors, and will be dependent upon our financial condition, results of operations, capital requirements, limitations under our credit facility and Senior Notes (defined below) and other factors as our board may deem relevant at that time.

Comparison of Cumulative Return

The following graph compares the cumulative return on a $100 investment in our common stock over the last five fiscal years beginning January 1, 2008 through December 31, 2012, to that of the cumulative return on a $100 investment in the S&P 500 Composite, NYSE Arca Oil, and the Dow Jones U.S. Oil & Gas Index for the same period. In calculating the cumulative return, reinvestment of dividends, if any, is assumed. The indices are included for comparative purpose only. This graph is not "soliciting material," is not deemed filed with the SEC and is not to be incorporated by reference in 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 in any such filing.

COMPARISON OF CUMULATIVE TOTAL RETURN



ASSUMES $100 INVESTED ON JANUARY 1, 2008
ASSUMES DIVIDEND REINVESTED
FISCAL YEAR END DECEMBER 31, 2012

	12/31/07	12/31/08	12/31/09	12/31/10	12/31/11	12/31/12
Kodiak Oil & Gas Corp.	$ 100	$ 14	$ 101	$ 300	$ 432	$ 402
S&P 500 Composite	$ 100	$ 63	$ 80	$ 92	$ 94	$ 109
NYSE Arca Oil Index	$ 100	$ 65	$ 73	$ 85	$ 89	$ 93
Dow Jones U.S. Oil & Gas	$ 100	$ 64	$ 75	$ 90	$ 94	$ 98

Exchange Controls

Canada has no system of exchange controls. There are no exchange restrictions on borrowing from foreign countries nor on the remittance of dividends, interest, royalties and similar payments, management fees, loan repayments, settlement of trade debts, or the repatriation of capital. However, dividends remitted to U.S. Holders, as defined below, generally will be subject to Canadian withholding tax.

Except as provided in the Investment Canada Act (the "Act"), as amended by the Canada-United States Free Trade Implementation Act (Canada) and the Canada- United States Free Trade Agreement, there are no limitations specific to the rights of non-Canadians to hold or vote our common stock under the laws of Canada or the Yukon Territory or in our charter documents. Our company is not a "Canadian business," as defined in the Act; therefore, the limitations in the Act do not apply to our company.

Certain United States Federal Income Tax Considerations

The following is a general summary of certain material U.S. federal income tax considerations applicable to a U.S. Holder (as defined below) arising from and relating to the acquisition, ownership, and disposition of common shares of the Company.

This summary is for general information purposes only and does not purport to be a complete analysis or listing of all potential U.S. federal income tax considerations that may apply to a U.S. Holder arising from and relating to the acquisition, ownership, and disposition of common shares. Except as specifically set forth below, this summary does not discuss applicable tax reporting requirements. In addition, this summary does not take into account the individual facts and circumstances of any particular U.S. Holder that may affect the U.S. federal income tax consequences to such U.S. Holder, including specific tax consequences to a U.S. Holder under an applicable tax treaty. Accordingly, this summary is not intended to be, and should not be construed as, legal or U.S. federal income tax advice with respect to any U.S. Holder. Each U.S. Holder should consult its own tax advisor regarding the U.S. federal, U.S. federal alternative minimum, U.S. federal estate and gift, U.S. state and local tax, and foreign tax consequences relating to the acquisition, ownership and disposition of common shares.

No legal opinion from U.S. legal counsel or ruling from the Internal Revenue Service (the "IRS") has been requested, or will be obtained, regarding the U.S. federal income tax consequences of the acquisition, ownership, and disposition of common shares. This summary is not binding on the IRS, and the IRS is not precluded from taking a position that is different from, and contrary to, the positions taken in this summary. In addition, because the authorities on which this summary is based are subject to various interpretations, the IRS and the U.S. courts could disagree with one or more of the positions taken in this summary.

Scope of this Summary

Authorities

This summary is based on the Internal Revenue Code of 1986, as amended (the "Code"), Treasury Regulations (whether final, temporary, or proposed), published rulings of the IRS, published administrative positions of the IRS, U.S. court decisions, the Convention Between Canada and the United States of America with Respect to Taxes on Income and on Capital, signed September 26, 1980, as amended (the "Canada-U.S. Tax Convention"), and U.S. court decisions that are applicable and, in each case, as in effect and available, as of the date of this document. Any of the authorities on which this summary is based could be changed in a material and adverse manner at any time, and any such change could be applied on a retroactive or prospective basis which could affect the U.S. federal income tax considerations described in this summary. This summary does not discuss the potential effects, whether adverse or beneficial, of any proposed legislation that, if enacted, could be applied on a retroactive or prospective basis.

U.S. Holders

For purposes of this summary, the term "U.S. Holder" means a beneficial owner of common shares that is for U.S. federal income tax purposes:

- an individual who is a citizen or resident of the U.S.;
- a corporation (or other entity taxable as a corporation for U.S. federal income tax purposes) organized under the laws of the U.S., any state thereof or the District of Columbia;
- an estate whose income is subject to U.S. federal income taxation regardless of its source; or

- a trust that (1) is subject to the primary supervision of a court within the U.S. and the control of one or more U.S. persons for all substantial decisions or (2) has a valid election in effect under applicable Treasury regulations to be treated as a U.S. person.

Non-U.S. Holders

For purposes of this summary, a "non-U.S. Holder" is a beneficial owner of common shares that is not a U.S. Holder. This summary does not address the U.S. federal income tax consequences to non-U.S. Holders arising from and relating to the acquisition, ownership, and disposition of common shares. Accordingly, a non-U.S. Holder should consult its own tax advisor regarding the U.S. federal, U.S. federal alternative minimum, U.S. federal estate and gift, U.S. state and local tax, and foreign tax consequences (including the potential application of and operation of any income tax treaties) relating to the acquisition, ownership, and disposition of common shares.

U.S. Holders Subject to Special U.S. Federal Income Tax Rules Not Addressed

This summary does not address the U.S. federal income tax considerations applicable to U.S. Holders that are subject to special provisions under the Code, including the following U.S. Holders: (a) U.S. Holders that are tax-exempt organizations, qualified retirement plans, individual retirement accounts, or other tax-deferred accounts; (b) U.S. Holders that are financial institutions, underwriters, insurance companies, real estate investment trusts, or regulated investment companies; (c) U.S. Holders that are dealers in securities or currencies or U.S. Holders that are traders in securities that elect to apply a mark-to-market accounting method; (d) U.S. Holders that have a "functional currency" other than the U.S. dollar; (e) U.S. Holders that own common shares as part of a straddle, hedging transaction, conversion transaction, constructive sale, or other arrangement involving more than one position; (f) U.S. Holders that acquired common shares in connection with the exercise of employee stock options or otherwise as compensation for services; (g) U.S. Holders that hold common shares other than as a capital asset within the meaning of Section 1221 of the Code (generally, property held for investment purposes); (h) partnerships and other pass-through entities (and investors in such partnerships and entities); or (j) U.S. Holders that own or have owned (directly, indirectly, or by attribution) 10% or more of the total combined voting power of the outstanding shares of the Company. This summary also does not address the U.S. federal income tax considerations applicable to U.S. Holders who are (a) U.S. expatriates or former long-term residents of the U.S. subject to Section 877 of the Code, (b) persons that have been, are, or will be a resident or deemed to be a resident in Canada for purposes of the Tax Act; (c) persons that use or hold, will use or hold, or that are or will be deemed to use or hold common shares in connection with carrying on a business in Canada; (d) persons whose common shares constitute "taxable Canadian property" under the Tax Act; or (e) persons that have a permanent establishment in Canada for the purposes of the Canada-U.S. Tax Convention. U.S. Holders that are subject to special provisions under the Code, including U.S. Holders described immediately above, should consult their own tax advisor regarding the U.S. federal, U.S. federal alternative minimum, U.S. federal estate and gift, U.S. state and local tax, and foreign tax consequences relating to the acquisition, ownership and disposition of common shares.

If an entity that is classified as a partnership for U.S. federal income tax purposes holds common shares, the U.S. federal income tax consequences to such partnership and the partners of such partnership generally will depend on the activities of the partnership and the status of such partners. Partners of entities that are classified as partnerships for U.S. federal income tax purposes should consult their own tax advisor regarding the U.S. federal income tax consequences arising from and relating to the acquisition, ownership, and disposition of common shares.

Tax Consequences Not Addressed

This summary does not address the U.S. state and local, U.S. federal estate and gift, U.S. federal alternative minimum tax or foreign tax consequences to U.S. Holders of the acquisition, ownership, and disposition of common shares. Each U.S. Holder should consult its own tax advisor regarding the U.S. state and local, U.S. federal estate and gift, U.S. federal alternative minimum tax and foreign tax consequences of the acquisition, ownership, and disposition of common shares.

U.S. Federal Income Tax Consequences of the Acquisition, Ownership, and Disposition of Common Shares

If the Company is not considered a "passive foreign investment company" (a "PFIC", as defined below) at any time during a U.S. Holder's holding period, the following sections will generally describe the U.S. federal income tax consequences to U.S. Holders of the acquisition, ownership, and disposition of the Company's common shares.

Distributions on Common Shares

A U.S. Holder that receives a distribution, including a constructive distribution, with respect to the Company's common shares will be required to include the amount of such distribution in gross income as a dividend (without reduction for any applicable Canadian tax withheld from such distribution) to the extent of the current or accumulated "earnings and profits" of the Company. To the extent that a distribution exceeds the current and accumulated "earnings and profits" of the Company, such distribution will be treated (a) first, as a tax-free return of capital to the extent of a U.S. Holder's tax basis in the common shares and, (b) thereafter, as gain from the sale or exchange of such common shares (see "Disposition of Common Shares" below). However, the Company does not intend to maintain the calculations of earnings and profits in accordance with U.S. federal income tax principles, and each U.S. Holder should therefore assume that any distribution by the Company with respect to common shares will constitute ordinary dividend income. Dividends received on common shares generally will not be eligible for the "dividends received deduction." Subject to applicable limitations, dividends paid by the Company to non-corporate U.S. Holders, including individuals, generally will be eligible for the preferential tax rates applicable to long-term capital gains for dividends, provided certain holding period and other conditions are satisfied, including that the Company not be classified as a PFIC (as defined below) in the tax year of distribution or in the preceding tax year. The dividend rules are complex, and each U.S. Holder should consult its own tax advisor regarding the dividend rules.

Disposition of Common Shares

A U.S. Holder will recognize a gain or loss on the sale or other taxable disposition of common shares in an amount equal to the difference, if any, between (a) the amount of cash plus the fair market value of any property received and (b) such U.S. Holder's tax basis in the common shares sold or otherwise disposed of. Subject to the PFIC rules discussed below, any such gain or loss generally will be capital gain or loss, which will be long-term capital gain or loss if common shares are held for more than one year.

Preferential tax rates apply to long-term capital gains of a U.S. Holder that is an individual, estate, or trust. There are currently no preferential tax rates for long-term capital gains of a U.S. Holder that is a corporation. Deductions for capital losses are subject to significant limitations under the Code.

Receipt of Foreign Currency

The amount of any distribution paid in foreign currency to a U.S. Holder in connection with the ownership of common shares, or on the sale, exchange or other taxable disposition of common shares, generally will be equal to the U.S. dollar value of such foreign currency based on the exchange rate applicable on the date of receipt (regardless of whether such foreign currency is converted into U.S. dollars at that time). A U.S. Holder that receives foreign currency and converts such foreign currency into U.S. dollars at a conversion rate other than the rate in effect on the date of receipt may have a foreign currency exchange gain or loss, which generally would be treated as U.S. source ordinary income or loss. If the foreign currency received is not converted into U.S. dollars on the date of receipt, a U.S. Holder will have a basis in the foreign currency equal to its U.S. dollar value on the date of receipt. Each U.S. Holder should consult its own U.S. tax advisor regarding the U.S. federal income tax consequences of receiving, owning, and disposing of foreign currency.

Foreign Tax Credit

As described above under the heading "Exchange Controls," dividends paid to U.S. Holders generally will be subject to Canadian withholding tax. A U.S. Holder who pays (whether directly or through withholding) foreign income tax with respect to dividends paid on common shares generally will be entitled, at the election of such U.S. Holder, to receive either a deduction or a credit for such foreign income tax paid. Generally, a credit will reduce a U.S. Holder's U.S. federal income tax liability on a dollar-for-dollar basis, whereas a deduction will reduce a U.S. Holder's income subject to U.S. federal income tax. This election is made on a year-by-year basis and applies to all foreign taxes paid (whether directly or through withholding) by a U.S. Holder during a year.

Complex limitations apply to the foreign tax credit, including the general limitation that the credit cannot exceed the proportionate share of a U.S. Holder's U.S. federal income tax liability that such U.S. Holder's "foreign source" taxable income bears to such U.S. Holder's worldwide taxable income. In applying this limitation, a U.S. Holder's various items of income and deduction must be classified, under complex rules, as either "foreign source" or "U.S. source." In addition, this limitation is calculated separately with respect to specific categories of income. Dividends paid by the Company generally will constitute "foreign source" income and generally will be categorized as "passive income." Gain or loss recognized by a U.S. Holder on the sale or other taxable disposition of common shares generally will be treated as "U.S. source" for purposes of applying the U.S. foreign tax credit rules unless the gain is subject to tax in Canada and is resourced as "foreign source" under the Canada-U.S. Tax Convention and such U.S. Holder elects to treat such gain or loss as "foreign source."

The foreign tax credit rules are complex, and each U.S. Holder should consult its own tax advisor regarding the foreign tax credit rules.

Additional Tax on Passive Income

Certain individuals, estates and trusts whose income exceeds certain thresholds will be required to pay a 3.8% Medicare surtax on "net investment income" including, among other things, dividends and net gain from disposition of property (other than property held in a trade or business). U.S. Holders should consult with their own tax advisors regarding the effect, if any, of this tax on their ownership and disposition of common shares.

Passive Foreign Investment Company Rules

If the Company were to constitute a PFIC (as defined below) for any year during a U.S. Holder's holding period, then certain different and potentially adverse tax consequences would apply to such U.S. Holder's acquisition, ownership and disposition of common shares. The Company does not believe that it was a PFIC for the tax year ended December 31, 2011, and based on current business plans and financial projections, the Company does not expect that it will be a PFIC for the tax year ending December 31, 2013. The determination of whether the Company will be a PFIC for a taxable year depends, in part, on the application of complex U.S. federal income tax rules, which are subject to differing interpretations. In addition, whether the Company will be a PFIC for its current taxable year depends on the assets and income of the Company over the course of each such taxable year and, as a result, cannot be predicted with certainty as of the date of this document. Consequently, there can be no assurance regarding the Company's PFIC status for any taxable year during which U.S. Holders hold common shares, and there can be no assurance that the IRS will not challenge the determination made by the Company concerning its PFIC status.

The Company generally will be a PFIC under Section 1297 of the Code if, for a taxable year, (a) 75% or more of the gross income of the Company for such taxable year is passive income or (b) 50% or more of the assets held by the Company either produce passive income or are held for the production of passive income, based on the quarterly average of the fair market value of such assets. "Gross income" generally includes all revenues less the cost of goods sold, plus income from investments and from incidental or outside operations or sources, and "passive income" includes, for example, dividends, interest, certain rents and royalties, certain gains from the sale of stock and securities, and certain gains from commodities transactions. Active business gains arising from the sale of commodities generally are excluded from passive income if substantially all of a foreign corporation's commodities are (a) stock in trade of such foreign corporation or other property of a kind which would properly be included in inventory of such foreign corporation, or property held by such foreign corporation primarily for sale to customers in the ordinary course of business, (b) property used in the trade or business of such foreign corporation that would be subject to the allowance for depreciation under Section 167 of the Code, or (c) supplies of a type regularly used or consumed by such foreign corporation in the ordinary course of its trade or business.

In addition, for purposes of the PFIC income test and asset test described above, if the Company owns, directly or indirectly, 25% or more of the total value of the outstanding shares of another corporation, the Company will be treated as if it (a) held a proportionate share of the assets of such other corporation and (b) received directly a proportionate share of the income of such other corporation. In addition, for purposes of the PFIC income test and asset test described above, "passive income" does not include any interest, dividends, rents, or royalties that are received or accrued by the Company from a "related person" (as defined in Section 954(d)(3) of the Code), to the extent such items are properly allocable to the income of such related person that is not passive income.

Under certain attribution rules, if the Company is a PFIC, U.S. Holders will be deemed to own their proportionate share of any subsidiary of the Company which is also a PFIC (a "Subsidiary PFIC"), and will be subject to U.S. federal income tax on (i) a distribution on the shares of a Subsidiary PFIC or (ii) a disposition of shares of a Subsidiary PFIC, both as if the holder directly held the shares of such Subsidiary PFIC.

Under the default PFIC rules, a U.S. Holder would be required to treat any gain recognized upon a sale or disposition of our common shares as ordinary (rather than capital), and any resulting U.S. federal income tax may be increased by an interest charge which is not deductible by non-corporate U.S. Holders. Rules similar to those applicable to dispositions will generally apply to distributions in respect of our common shares which exceed a certain threshold level.

While there are U.S. federal income tax elections that sometimes can be made to mitigate these adverse tax consequences (including, without limitation, the "QEF Election" and the "Mark-to-Market Election"), such elections are available in limited circumstances and must be made in a timely manner. U.S. Holders are urged to consult their own tax advisers regarding the potential application of the PFIC rules to the ownership and disposition of our common shares, and the availability of certain U.S. tax elections under the PFIC rules.

U.S. Holders should be aware that, for each taxable year, if any, that the Company or any Subsidiary PFIC is a PFIC, the Company can provide no assurances that it will satisfy the record keeping requirements of a PFIC, or that it will make available to U.S. Holders the information such U.S. Holders require to make a QEF Election under Section 1295 of the Code with respect of the Company or any Subsidiary PFIC. Each U.S. Holder should consult its own tax advisor regarding the availability of, and procedure for making, a QEF Election with respect to the Company and any Subsidiary PFIC.

The above discussion is only a brief summary of the PFIC rules. The PFIC rules are complex, and each U.S. Holder should consult its own financial advisor, legal counsel, or accountant regarding the PFIC rules and how the PFIC rules may affect the U.S. federal income tax consequences of the acquisition, ownership, and disposition of common shares.

Information Reporting; Backup Withholding Tax

Under U.S. federal income tax law and Treasury Regulations, certain categories of U.S. Holders must file information returns with respect to their investment in, or involvement in, a foreign corporation. For example, U.S. return disclosure obligations (and related penalties) are imposed on individuals who are U.S. Holders that hold certain specified foreign financial assets in excess of $50,000. The definition of specified foreign financial assets includes not only financial accounts maintained in foreign financial institutions, but also, unless held in accounts maintained by a financial institution, any stock or security issued by a non-U.S. person, any financial instrument or contract held for investment that has an issuer or counterparty other than a U.S. person and any interest in a foreign entity. U. S. Holders may be subject to these reporting requirements unless their common shares are held in an account at a domestic financial institution. Penalties for failure to file certain of these information returns are substantial. U.S. Holders should consult with their own tax advisors regarding the requirements of filing information returns under these rules, including the requirement to file an IRS Form 8938 for prior tax years in which the obligation to file such form was suspended.

Payments made within the U.S. or by a U.S. payor or U.S. middleman, of dividends on, and proceeds arising from the sale or other taxable disposition of, common shares will generally be subject to information reporting and backup withholding tax, at the rate of 28% , if a U.S. Holder (a) fails to furnish such U.S. Holder's correct U.S. taxpayer identification number (generally on Form W-9), (b) furnishes an incorrect U.S. taxpayer identification number, (c) is notified by the IRS that such U.S. Holder has previously failed to properly report items subject to backup withholding tax, or (d) fails to certify, under penalty of perjury, that such U.S. Holder has furnished its correct U.S. taxpayer identification number and that the IRS has not notified such U.S. Holder that it is subject to backup withholding tax. However, certain exempt persons generally are excluded from these information reporting and backup withholding rules. Backup withholding is not an additional tax. Any amounts withheld under the U.S. backup withholding tax rules will be allowed as a credit against a U.S. Holder's U.S. federal income tax liability, if any, or will be refunded, if such U.S. Holder furnishes required information to the IRS in a timely manner. Each U.S. Holder should consult its own tax advisor regarding the information reporting and backup withholding rules.

Issuer Purchases of Equity Securities

During the fiscal year ended December 31, 2012, neither the Company nor any affiliated purchaser purchased any of the Company's equity securities.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected consolidated financial data as of and for the years ended December 31, 2008 through December 31, 2012. The data as of and for the fiscal years ended December 31 for the respective years was derived from our historical consolidated financial statements and the accompanying notes included elsewhere in this Annual Report on Form 10-K and in our prior Annual Reports on Form 10-K, as applicable.

The following selected consolidated financial information should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Conditions and Results of Operations" and the consolidated financial statements and the notes thereto included in "Item 8. Financial Statements and Supplementary Data" presented elsewhere in this Annual Report on Form 10-K. Also see "Recently Adopted Accounting Pronouncements" included in the notes to the consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

	For the Years Ended December 31,				
	2012	2011	2010	2009	2008
	(In thousands, except per share data)				
Consolidated Statements of Income Information:					
Revenues:					
Oil sales	$ 390,425	$ 115,692	$ 30,212	$ 10,652	$ 5,397
Gas sales	18,265	4,294	783	625	1,372
Total revenues	408,690	119,986	30,995	11,277	6,769
Operating expenses:					
Oil and gas production	85,498	26,885	6,795	2,220	3,579
Depletion, depreciation, amortization and accretion	155,634	32,068	8,234	3,159	4,172
Asset impairment	—	—	—	—	47,500
General and administrative	34,528	19,495	12,190	8,522	8,212
Total operating expenses	275,660	78,448	27,219	13,901	63,463
Operating income (loss)	133,030	41,538	3,776	(2,624)	(56,694)
Other income (expense):					
Gain (loss) on commodity price risk management activities	44,602	(20,114)	(6,146)	—	—
Interest income (expense), net	(22,911)	(18,887)	(39)	53	196
Other income	3,663	1,338	7	8	—
Total other income (expense)	25,354	(37,663)	(6,178)	61	196
Income (loss) before income taxes	158,384	3,875	(2,402)	(2,563)	(56,498)
Income tax expense	26,800	—	—	—	—
Net income (loss)	$ 131,584	$ 3,875	$ (2,402)	$ (2,563)	$ (56,498)
Net income (loss) per share:					
Basic	$ 0.50	$ 0.02	$ (0.02)	$ (0.02)	$ (0.62)
Diluted	$ 0.49	$ 0.02	$ (0.02)	$ (0.02)	$ (0.62)
Other Financial Information:					
Net cash provided by operating activities	$ 272,679	$ 53,913	$ 10,315	$ 9,396	$ (2,174)
Net cash used in investing activities	$ (1,348,07)	$ (590,749)	$ (200,009)	$ (28,155)	$ (20,911)
Net cash provided by financing activities	$ 1,017,855	$ 517,242	$ 266,007	$ 36,064	$ 17,651
Consolidated Balance Sheet Information:					
Total assets	$ 2,373,636	$ 1,699,477	$ 369,937	$ 79,683	$ 39,016
Long-term debt	$ 1,100,622	$ 750,000	$ 40,000	$ —	$ —
Total stockholders' equity	$ 1,033,472	$ 839,680	$ 299,047	$ 69,928	$ 32,998

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

The following discussion and analysis should be read in conjunction with the "Selected Financial Data" in Item 6 above and our historical consolidated financial statements and the accompanying notes included elsewhere in this Annual Report on Form 10-K.

Overview

We are an independent energy company focused on the exploration, exploitation, acquisition and production of crude oil and natural gas in the Rocky Mountain region of the United States. Our corporate strategy is to internally identify prospects, acquire lands encompassing those prospects and evaluate those prospects using subsurface geology and geophysical data and exploratory drilling. Using this strategy, we have developed an oil and natural gas portfolio of proved reserves, as well as development and exploratory drilling opportunities on high potential conventional and unconventional oil and natural gas prospects.

Our oil and natural gas reserves and operations are primarily concentrated in the Williston Basin of North Dakota and Montana and, to a lesser extent, the Green River Basin of Wyoming and Colorado. The most significant prospects in our portfolio are our assets in the Williston Basin, where the principal target of drilling is the Bakken Shale hydrocarbon system highlighted by production from the Middle Bakken member, located between two Bakken shales that serve as the source rock, and the TFS member, positioned immediately below the Lower Bakken Shale. As of December 31, 2012, we owned an interest in approximately 228,200 gross (154,400 net) acres in the Williston Basin and have an interest in 268 gross (121.9 net) producing wells in the Williston Basin.

Oil and Gas Property Acquisitions

The following is a summary of our acquisitions during the last two fiscal years:

January 2012 Acquisition

On January 10, 2012, we acquired certain oil and gas leaseholds, overriding royalty interests and producing properties located in North Dakota, and various other related rights, permits, contracts, equipment and other assets, including the assignment and assumption of a drilling rig contract (the "January 2012 Acquisition"). The effective date for this acquisition was September 1, 2011. The producing properties acquired in January 2012 contributed revenue to us for the years ended December 31, 2012 and 2011 of $33.6 million and $0, respectively. Oil and gas proved reserves acquired were 11,891.3 MBOE.

We closed this acquisition for aggregate consideration of approximately $638.2 million. This consideration was comprised of (i) 5,055,612 shares of the Company's common stock and (ii) cash consideration in an amount equal to approximately $588.4 million. We funded the cash balance due at closing through the release from escrow of the proceeds from our November 2011 high yield debt and equity offering.

Through this acquisition, we acquired approximately 50,000 net leasehold acres and net production of approximately 3,600 barrels of oil equivalent per day located primarily in McKenzie and Williams Counties, N.D. We operate substantially all of the leasehold acquired through this acquisition.

October 2011 Acquisition

On October 28, 2011, we acquired interests in approximately 13,400 net acres of Williston Basin leaseholds, and related producing properties located primarily in Williams County, North Dakota along with various other related rights, permits, contracts, equipment and other assets. The seller in this transaction received cash consideration of approximately $248.2 million. The effective date for the acquisition was August 1, 2011. The producing properties acquired in October 2011 contributed revenue to us for the years ended December 31, 2012 and 2011 of $27.2 million and $5.6 million, respectively.

June 2011 Acquisition

On June 30, 2011, we acquired interests in approximately 25,000 net acres of Williston Basin leaseholds and related producing properties located in McKenzie County, North Dakota along with various other related rights, permits, contracts, equipment and other assets for a combination of cash and stock. The seller in this transaction received 2,500,000 shares of the Company's common stock valued at approximately $14.0 million and cash consideration of approximately $71.5 million. The effective date for the acquisition was April 1, 2011. The producing properties acquired in June 2011 contributed revenue to us for the years ended December 31, 2012 and 2011 of $1.5 million and $1.4 million, respectively.

2012 Capital Expenditures and 2013 Capital Budget

The following table sets forth our actual capital expenditures for the years ended December 31, 2012, 2011, and 2010 and our capital expenditures budget for 2013. Capital expenditures include cash expenditures, accrued expenditures, oil and gas property acquisitions through the issuance of common stock and are net of divestitures (in millions).

	For the Years Ended December 31,			
	2013 Budget	2012 Actual	2011 Actual	2010 Actual
Costs incurred:				
Acquisitions(1)				
Proved oil and gas properties	$ —	$ 322.8	$ 152.5	$ 32.2
Unproved oil and gas properties	—	313.1	168.0	77.2
Asset retirement obligations	—	0.8	0.3	0.2
Total acquisitions	—	636.7	320.8	109.6
Capital Expenditures				
Operated drilling and completion costs	600.0	664.5	194.2	63.3
Non-operated drilling and completion costs	140.0	145.9	66.4	3.5
Total drilling and completion costs	740.0	810.4	260.6	66.8
Salt water disposal wells and facilities	23.0	10.2	—	—
Leasehold acquisitions	12.0	17.9	14.9	18.5
Total capital expenditures	775.0	838.5	275.5	85.3
Asset retirement obligations	—	4.1	1.3	0.6
Capitalized interest	—	46.0	8.4	0.5
Total capital expenditures including non-cash items	775.0	888.6	285.2	86.4
Total capitalized costs	**$ 775.0**	**$ 1,525.3**	**$ 606.0**	**$ 196.0**

(1) Includes acquisitions accounted for as business combinations.

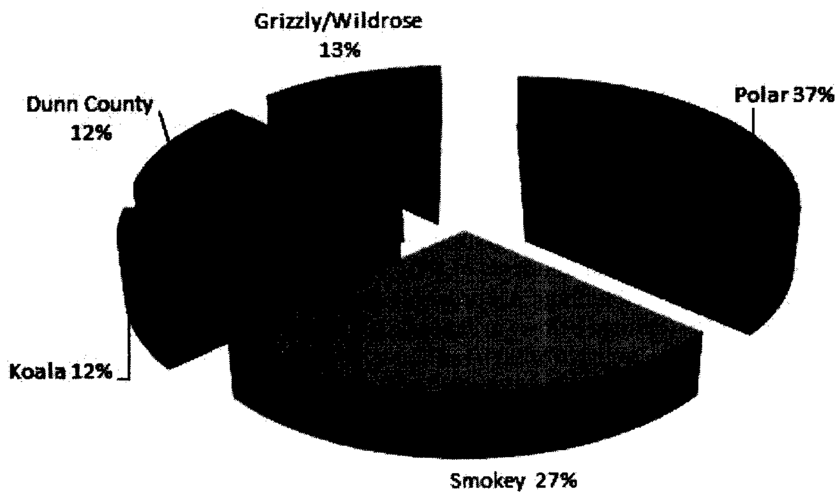
The table below summarizes the wells spud and completed during the year ended December 31, 2012 as a result of our 2012 capital expenditures. For the year ended December, 31 2012, we incurred capital expenditures of $810.4 million related to drilling and completion operations (exclusive of our January 2012 Acquisition). At December 31, 2012, we had 18 gross (14.0 net) operated and 16 gross (1.5 net) non-operated wells waiting on completion.

	Spud		Completed	
	Gross	Net	Gross	Net
For the Year Ended December 31, 2012				
Operated wells	69	57.1	64	52.4
Non-operated wells	77	13.6	60	10.2
	146	70.7	124	62.6

Industry wide, exploration and development activity in the Williston Basin continued at a high level in 2012. During the year, our drilling operations benefited from improved efficiencies resulting in decreased spud-to-rig-release drilling times. As the Basin has experienced a significant increase in third party oil field services over the past year and operators gain efficiencies through more pad drilling, we have seen improved field services and reduced costs. During the year, our completed well costs trended downward from approximately $12 million per well, including surface facilities and pipeline connections, to approximately $11 million by year end. Further, we recently renegotiated agreements with certain suppliers, which we expect will reduce our drilling and completion costs to approximately $10 million per well in early 2013.

Our Board of Directors approved a $775.0 million capital expenditure budget for 2013, all of which is allocated to oil and gas activities in the Williston Basin of North Dakota. We have allocated $600.0 million to the drilling and completion of 75 gross (61 net) operated wells; $140.0 million to non-operated drilling and completion activities for 14 net wells; and $35.0 million for water disposal systems, well connections and acreage acquisitions. We anticipate funding this capital program through existing cash on hand, our expected cash flow from operations, and borrowing capacity expected to be available under our credit facility. As of the date of this filing, we had a borrowing base and total commitment for the credit facility of $450.0 million, of which $400.0 million is currently available.

The following chart illustrates our expected capital allocation by operating area:



We are currently operating seven drilling rigs and anticipate operating six to seven drilling rigs for the majority of 2013. Our rig termination schedule allows us to adjust capital expenditures in reaction to economic conditions such as a decline in crude oil prices.

We are proceeding with a pilot program to test 12 wells within a drilling spacing unit in each of our Polar and Smokey operating areas. In each project, six wells will target the Middle Bakken and six wells will target intervals within the Three Forks Formation.

The Polar pilot project wells are being drilled from three four-well pads. Geologic and geophysical work on the DSU will include cores and high-resolution logs to evaluate the Middle Bakken and all benches of the TFS. In addition, a micro seismic program is planned to further evaluate completion procedure effectiveness.

In our Smokey block, two wells within the test DSU are now producing, and three additional well bores have recently been drilled into the same DSU. We expect to drill the remaining seven wells following drilling of the Polar pilot program.

Water disposal and oil and gas lines are being constructed in each of the test areas and should be operational before completion activities begin. Results from these pilot projects will be evaluated throughout 2013.

Our 2013 capital expenditure budget is subject to various factors, including market conditions, oilfield services and equipment availability, commodity prices and drilling results. While we continue to explore opportunities to expand our acreage position, our current budget is primarily allocated to drilling and completing wells. If we choose to pursue the acquisition of significant additional leaseholds, we would need to increase our budget accordingly.

Other factors that could cause us to further adjust our capital expenditure budget include, among other things, increases or decreases in service and material costs, the formation of joint ventures with other exploration and production companies, the divestiture of non-strategic assets, changes in commodity prices or well performance that differ from our forecasts, any of which could affect our operating cash flow.

Liquidity and Capital Resources

Our 2013 drilling program is designed to provide flexibility in identifying suitable well locations and in the timing and size of capital investment. We plan to finance our 2013 capital expenditure budget of $775.0 million and our obligations under our Senior Notes and other contractual commitments through existing cash on hand, cash flows from operations and borrowing capacity expected to be available under our credit facility, as discussed in more detail below:

Sources of Capital

Cash flow from operations. We expect our cash flow from operations to continue to increase commensurate with our anticipated increase in sales volumes. We have been able to increase our volumes on a quarter over quarter basis for the past three years. This increase is directly related to our successful operations as we have developed our properties. If we are able to continue to drill and complete our wells as anticipated and they produce at rates similar to those generated by our existing wells, subject to the changes in the market price of crude oil, we would expect our production rates and operating cash flows to continue to increase as we continue to develop our properties.

Credit facility. As of December 31, 2012, our maximum credit available under the credit facility is $750.0 million with a current borrowing base and aggregate commitments of $450.0 million. As of December 31, 2012, we had available borrowings under the credit facility of $155.0 million. All proceeds from the issuance of the $350.0 million aggregate principal amount of 5.50% senior notes (defined below) in January 2013 were used to reduce amounts outstanding under our credit facility. As of the date of this filing, we have $400.0 million available under this credit facility. The ability to maintain and increase this facility and borrow additional funds is dependent on a number of variables, including our proved reserves, and assumptions regarding the price at which oil and natural gas can be sold. Further, we expect that our borrowing base will increase with the addition of proved properties resulting from our ongoing drilling and completion activities. We are subject to restrictive covenants under the credit facility. For further details on our credit facility and Senior Notes please refer to *Note 5-Long-Term Debt* under Item 8 in this Annual Report.

Capital Requirements Outlook

We are dependent on our anticipated cash flows from operations and the expected borrowing availability under our credit facility to fund our 2013 capital expenditures budget, our obligations under our Senior Notes and other contractual commitments (please refer to *Note 5-Long-Term Debt* and *Note 14-Commitments and Contingencies* under Item 8 in this Annual Report for further details). While we expect such sources of capital to be sufficient for such purposes, there can be no assurance that we will achieve our anticipated future cash flows from operations, that credit will be available under our credit facility when needed, or that we would be able to complete alternative transactions in the capital markets, if needed. Our ability to obtain financing on commercially reasonable terms is dependent on a number of factors, many of which we cannot control, including changes in our credit rating, interest rates, market perceptions of us and the oil and natural gas exploration and production industry and tax burdens due to new tax laws.

If our existing and potential sources of liquidity are not sufficient to satisfy such commitments and to undertake our currently planned expenditures, we believe that we have the flexibility in our commitments to alter our drilling program. Since we operate the majority of our acreage, we have the ability to adjust our drilling schedule to reflect a change in commodity price or oil field service environment. The majority of our acreage is currently producing and the remaining acreage could be held by production within the primary term of the lease, even with a reduced number of drilling rigs. If we were not successful in obtaining sufficient funding or completing an alternative transaction on a timely basis on terms acceptable to us, we would be required to curtail our planned expenditures or restructure our operations (including reducing our rig count and sub-contracting our pressure pumping services agreement, either of which may in certain circumstances result in termination fees depending on the timing and requirements of the underlying agreements), we would be unable to implement our original exploration and drilling program, and we may be unable to service our debt obligation or satisfy our contractual obligations.

Senior Notes

8.125% Senior Notes due 2019. In November 2011, we issued in a private placement at par $650.0 million principal amount of 8.125% senior notes due December 1, 2019 (which notes were subsequently exchanged for SEC registered notes pursuant to the Exchange Offer (defined below) (the "Original 2019 Notes"). The net proceeds from such issuance were primarily used to finance our January 2012 Acquisition and to repay in full our second lien credit agreement, which was then terminated. In May 2012, we issued in a private placement an additional $150.0 million aggregate principal amount of our senior notes due December 1, 2019 at 104.0% of par, resulting in a $6.0 million premium on the issuance (which notes were subsequently exchanged for SEC registered notes pursuant to the Exchange Offer (the "Follow-On 2019 Notes", and together with the "Original 2019 Notes", the "2019 Notes"). The net proceeds from such issuance were used to repay all borrowings on our credit facility and to fund our capital expenditure program and general corporate purposes. The interest on our 2019 Notes is payable on June 1 and December 1 of each year. On July 20, 2012, the Company filed a registration statement on Form S-4 (No. 333-182783, amended on October 9, 2012 and declared effective by the SEC on October 11, 2012) with the SEC in accordance with registration rights agreements associated with the privately placed 2019 Notes. On October 12, 2012, the Company commenced a registered exchange offer ("Exchange Offer") pursuant to which all of the holders of the privately placed 2019 Notes exchanged their notes for SEC-registered 2019 Notes. The Exchange Offer closed on November 16, 2012.

5.50% Senior Notes due 2021. In January 2013, we issued at par $350.0 million principal amount of 5.50% senior notes due January 15, 2021 (the "2021 Notes", and together with the 2019 Notes, the "Senior Notes"). All of the net proceeds from this issuance were used to repay borrowings on our credit facility. The interest on our 2021 Notes is payable on January 15 and July 15 of each year. In connection with the sale of our 2021 Notes, we entered into a registration rights agreement pursuant to which we agreed (1) to file an exchange offer registration statement to allow the holders to exchange the 2021 Notes for SEC-registered notes and (2) to file, under certain circumstances, a shelf registration statement to cover resales of the 2021 Notes. If we fail to complete the registered exchange offer or the shelf registration statement has not been declared effective within specified time periods, we will be required to pay liquidated damages by way of additional interest on the 2021 Notes.

For further discussion regarding our Senior Notes, please refer to *Note 5-Long-Term Debt* under Item 8 in this Annual Report.

Working Capital

As part of our cash management strategy, we frequently use available funds to reduce any balance on our credit facility. Because of this, we generally maintain low cash and cash equivalent balances. Since our principal source of operating cash flows (proved reserves to be produced in future years) is not considered working capital, we often have low or negative working capital. Our working capital was a deficit of $49.4 million at December 31, 2012, as compared to a positive $72.8 million at December 31, 2011.

Registered Offerings

Historically, we have financed our operations, property acquisitions and other capital investments from the proceeds of offerings of our equity and debt securities. We currently have on file with the SEC a universal shelf registration statement to allow us to offer an indeterminate amount of securities in the future. Under the registration statement, we may offer from time to time debt securities, common stock, preferred stock, warrants and other securities or any combination of such securities in amounts, prices and on terms announced when and if the securities are offered. The specifics of any future offerings, along with the use of proceeds of any securities offered, will be described in detail in a prospectus supplement at the time of any such offering.

Derivative Instruments

We utilize various derivative instruments in connection with anticipated crude oil sales to minimize the impact of product price fluctuations and ensure cash flow for future capital needs. Currently, we utilize swaps and "no premium" collars. Current period settlements on commodity derivative instruments impact our liquidity, since we are either paying cash to, or receiving cash from, our counterparties. If actual commodity prices are higher than the fixed or ceiling prices in our derivative instruments, our cash flows will be lower than if we had no derivative instruments. Conversely, if actual commodity prices are lower than the fixed or floor prices in our derivative instruments, our cash flows will be higher than if we had no derivative instruments.

Cash Flow Analysis

The following is a summary of our change in cash and cash equivalents for the years ended December 31, 2012, 2011 and 2010 (in thousands):

	For the Years Ended December 31,		
	2012	2011	2010
Net cash provided by operating activities	$ 272,679	$ 53,913	$ 10,315
Net cash used in investing activities	$ (1,348,078)	$ (590,749)	$ (200,009)
Net cash provided by financing activities	$ 1,017,855	$ 517,242	$ 266,007
Increase (decrease) in cash and cash equivalents	$ (57,544)	$ (19,594)	$ 76,313

Net cash provided by operating activities. The key components of our net cash provided by operating activities are our sales volumes (in particular, our crude oil sales volumes) and commodity prices (in particular, crude oil prices). For the year ended December 31, 2012 as compared to the year ended December 31, 2011, our net cash provided by operating activities increased by $218.8 million, primarily from increased crude oil sales volumes attributable to our successful drilling and completions in our core Middle Bakken and TFS formations in the Williston basin. Additionally, we utilize derivative instruments, as further discussed in the Operating Results section below, to partially mitigate the impact of decreases in crude oil prices.

Net cash used in investing activities. The primary driver in our net cash used for investing activities is our capital expenditure budget, which consists of both our ongoing drilling and completion expenditures and our acquisition expenditures. For the year ended December 31, 2012 as compared to the year ended December 31, 2011, our net cash used in investing activities increased by $757.3 million. This increase is primarily attributed to our January 2012 Acquisition, which required $588.4 million in cash, and secondarily, to our significantly increased capital expenditures for drilling and completions during the year ended December 31, 2012 as compared to the year ended December 31, 2011.

Net cash provided by financing activities. For the year ended December 31, 2012 as compared to the year ended December 31, 2011, our net cash provided by financing activities increased by $500.6 million. This was a result of our receipt from escrow of $670.6 million related to the issuance of our Original 2019 Notes in November 2011 ($588.4 million of which was used to fund our January 2012 Acquisition and $100.0 million of which was used to repay our second lien credit agreement) and the receipt of $151.8 million in net proceeds from the issuance of our Follow-On 2019 Notes in May 2012.

Operating Results

The Bakken is the only field (as such term is used within the meaning of applicable regulations of the SEC) that contains more than 15% of our total proved reserves. At December 31, 2012, this field contained 99.8% of our total proved reserves. Our revenues are directly affected by oil and natural gas commodity prices, which can fluctuate dramatically. The commodity prices are largely beyond our control and are difficult to predict. We have seen significant volatility in oil and natural gas prices in recent years. The following table discloses our oil and gas sales volumes from the Bakken field and from our other fields combined and in total, for the periods indicated:

	For the Years Ended December 31,		
	2012	2011	2010
Sales Volume (Bakken):			
Oil (MBbls)	4,686.9	1,304.7	402.3
Gas (MMcf)	3,259.1	472.3	11.1
Sales Volume (Other):			
Oil (MBbls)	17.2	39.8	30.0
Gas (MMcf)	42.9	50.4	151.8
Sales Volume (Total):			
Oil (MBbls)	4,704.1	1,344.5	432.3
Gas (MMcf) (1)	3,302.0	522.7	162.9
Sales volumes (MBOE)	5,254.4	1,431.6	459.5

(1) Does not include production of natural gas that was flared, all of which is related to the Bakken field. For the years ended December 31, 2012, 2011 and 2010, we flared gas in the amounts of 3,311.2 MMcf, 806.7 MMcf and 282.7 MMcf, respectively.

Sales prices received, and costs incurred, presented on a per BOE basis, for the years ended December 31, 2012, 2011 and 2010 are summarized in the following table:

	For the Years Ended December 31,		
	2012	2011	2010
Sales Price:			
Oil ($/Bbls)	$ 83.00	$ 86.05	$ 69.89
Gas ($/Mcf)(1)	$ 5.53	$ 8.22	$ 4.81
BOE ($/BOE)	$ 77.78	$ 83.81	$ 67.46
Commodity Price Risk Management Activities ($/Sales BOE):			
Realized gain (loss)	$ 2.57	$ (2.72)	$ (0.88)
Production costs ($/Sales BOE):			
Lease operating expenses	$ 6.04	$ 8.67	$ 7.03
Production and property taxes	$ 8.34	$ 9.04	$ 7.49
Gathering, transportation, marketing	$ 1.89	$ 1.07	$ 0.26
DDA	$ 29.62	$ 22.40	$ 17.92
G&A	$ 6.57	$ 13.62	$ 26.53
Stock-based compensation	$ 2.12	$ 3.63	$ 9.70

(1) Average gas price received at the wellhead includes proceeds from natural gas liquids under percentage of proceeds contracts.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Oil sales revenues. Oil sales revenues increased by $274.7 million to $390.4 million for the year ended December 31, 2012 as compared to oil sales of $115.7 million for the year ended December 31, 2011. In 2012, our crude oil sales averaged 12,853 barrels per day. Our oil sales volume increased 250% to 4,704.1 thousand barrels ("MBbls") in 2012 as compared to 1,344.5 MBbls in 2011. The volume increase is due to the development of our Bakken properties as well as our October 2011 property acquisition and January 2012 Acquisition. Of the 3,359.6 MBbls increase in oil sales volume, 643.8 MBbls is related to the increase in production from producing wells acquired in these acquisitions and 2,715.8 MBbls is attributed to our ongoing development of our legacy properties and undeveloped acreage. The increase in crude oil revenues in 2012 is attributed to a $278.8 million positive impact due to increased sales volumes. However, the average price we realized on the sale of our oil decreased from $86.05 per barrel for the year ended December 31, 2011, to $83.00 for the year ended December 31, 2012 resulting in a negative impact of $4.1 million in oil sales revenues. Overall, 101.5% of the increase in oil sales revenue was attributed to increased volumes and negative 1.5% was attributed to the decrease in crude oil prices received.

Natural gas sales revenues. Natural gas revenues increased by $14.0 million to $18.3 million for the year ended December 31, 2012 as compared to natural gas revenues of $4.3 for the year ended December 31, 2011. Natural gas sales volumes increased by 2,779.3 million cubic feet ("MMcf") to 3,302.0 MMcf for the year ended December 31, 2012. In 2012, our natural gas sales averaged 9.0 MMcf per day. The average price we realized on the sale of our natural gas was $5.53 per Mcf in 2012 compared to $8.22 per Mcf in 2011. The decrease in natural gas prices realized resulted in a $1.4 million decrease in natural gas revenues and the increase in natural gas sales volumes resulted in a $15.4 million increase in natural gas revenues. Overall, 110.1% of the increase in natural gas sales revenue was attributed to increased sales volumes and negative 10.1% was attributed to the decrease in natural gas prices received. The volume increase is due to the development of our Bakken properties as well as our October 2011 property acquisition and January 2012 Acquisition. Of the 2,779.3 MMcf increase in natural gas sales volume, 596.7 MMcf is related to the increase in production from producing wells acquired in these acquisitions and 2,182.6 MMcf is attributed to our ongoing development of our legacy properties and undeveloped acreage. Although gas from certain wells continues to be flared, during 2011 and throughout 2012, we connected the majority of our wells to gas pipelines which allowed us to capture the related sales revenue. As these third-parties expand their processing capacity, we expect additional gas volumes to be gathered, processed and sold.

Oil and gas production expense. Our oil and gas production expense increased by $58.6 million to $85.5 million for the year ended December 31, 2012, from $26.9 million for the year ended December 31, 2011. The increase is due to a $30.9 million increase in production taxes, a $19.3 million increase in lease operating expenses ("LOE"), and an $8.4 million increase in gathering, transportation and marketing expenses. The production tax increase is attributable to increased revenue as it is calculated as a fixed percentage of sales revenue. LOE increased year over year due to a higher number of wells that we operate or participate in. On a per unit basis, LOE decreased from $8.67 per barrel sold in 2011 to $6.04 per barrel sold in 2012. The largest component of our lease operating expense continues to be the disposal of produced water. To date, the majority of water has been transported by truck to third-party disposal facilities. Availability of both trucking and third party disposal facilities has improved, which has decreased our LOE on a per unit basis.

To further reduce water disposal costs, in 2012, we drilled water disposal wells on several of our producing areas and are constructing water gathering systems where appropriate. As we connect existing and future wells to these water gathering systems, we expect our LOE related to water disposal to continue to decrease on a per unit basis.

Depletion, depreciation, amortization and abandonment liability accretion ("DD&A") expense. Our depletion, depreciation, amortization and abandonment liability accretion expense increased $123.5 million to $155.6 million for the year ended December 31, 2012, from $32.1 million for the year ended December 31, 2011. This increase is due to more volumes being sold in 2012 as sales increased by approximately 3,822.8 MBOE. On a per unit basis, DD&A increased from $22.40 per BOE in 2011 to $29.62 per BOE in 2012. This increase in the DD&A rate was primarily the result of the allocation of the purchase price to proved properties related to our acquisitions in October 2011 and our January 2012 Acquisition. Acquired proved reserves are valued at fair market value on the date of acquisition, which contributes to a higher amortization base, as compared to our historical cost of acquiring leasehold and developing our properties. To date, the fair value of our acquired proved reserves has been higher than our historical cost of developing our properties even though the resulting EURs are equivalent. In addition our undeveloped properties acquired in our October 2011 property acquisition and our January 2012 Acquisition carry higher costs than our legacy properties as they were valued at fair market value on the date of acquisition. As a portion of these undeveloped properties were proved, their related costs were transferred to the amortization base, which also increased the DD&A rate per BOE. Therefore, the increase in the ratio of costs subject to amortization to the reserves acquired is greater than our internally developed properties. We believe that, although initially these acquisitions increase our DD&A rate per BOE over the development of the acquired properties, the resulting rates will decline with infill drilling and the addition of the related reserves.

General and administrative ("G&A") expense. G&A expense increased by $15.0 million to $34.5 million for the year ended December 31, 2012, from $19.5 million for the year ended December 31, 2011. This increase is due to the growth in personnel and related costs as we have expanded our operational activities. Total employees have increased to 102 at year-end 2012 from 74 at year-end 2011. For the year ended December 31, 2012, we had an average of 93 employees as compared to 56 in 2011, an increase of 65%. On a per unit basis, G&A decreased from $13.62 per barrel sold in 2011 to $6.57 per barrel sold in 2012. The decrease is primarily due to our increase in sales volumes from our ongoing Bakken development program.

Our G&A expense includes the non-cash expense for stock-based compensation for stock options and share grants under our 2007 Stock Incentive Plan. For the years ended December 31, 2012, this expense was $11.1 million as compared to $5.2 million in 2011.

Operating income. Our operating income was approximately $133.0 million for the year ended December 31, 2012, as compared to approximately $41.5 million for the year ended December 31, 2011. This 220% increase in operating income is attributed to our on-going successful completions of wells and resulting increase in sales volumes in our Bakken play.

(Gain) loss on commodity price risk management activities. Primarily due to the decrease in NYMEX crude oil prices at December 31, 2012 as compared to December 31, 2011, we incurred a total gain on our price risk management activities of $44.6 million for the year ended December 31, 2012 as compared to a loss of $20.1 million for the year ended December 31, 2011. This gain is a result of our hedging program used to mitigate our exposure to commodity price fluctuations. This gain was comprised of approximately $13.5 million of realized gains for transactions that were settled during 2012 and $31.1 million of unrealized gains for the mark-to-market of forward transactions. The unrealized gain is a non-cash adjustment for the value of our risk management transactions at December 31, 2012. These transactions will continue to change in value until the transactions are settled and we will likely add to our hedging program. Therefore, we expect our net income to reflect the volatility of commodity price forward markets. Our cash flows will only be affected upon settlement of the transactions at the current market prices at that time.

Interest income (expense), net. For the year ended December 31, 2012, we recognized interest expense of approximately $22.9 million, as compared to $19.0 million for the year ended December 31, 2011.

We incurred interest expense for the years ended December 31, 2012 and 2011 of approximately $63.4 million and $12.4 million, respectively, related to the credit facilities and our 2019 Notes. Included in interest expense for the year ended December 31, 2012 and 2011 was the amortization of deferred financing costs and bond premium of $2.6 million and $15.0 million, respectively. Additionally, in the first quarter of 2012, we recognized a $3.0 million prepayment penalty for the early termination of the second lien credit agreement. For the year ended December 31, 2012 and 2011, we capitalized interest costs of $46.0 million and $8.4, respectively.

Income tax expense. As discussed in *Note 6—Income Taxes* under Item 8 in this Annual Report, through March 31, 2012, we had a full valuation allowance against our U.S. and Canada net deferred tax assets. During the second quarter of 2012, we concluded that it was appropriate to reverse the U.S. valuation allowance, but retained a full valuation allowance on our Canadian net deferred tax assets. We recognized a net deferred tax liability and income tax expense of $26.8 million as of December 31, 2012 and for the year then ended, respectively. For the year ended December 31, 2011, there was no income tax expense or benefit recognized as we had a full valuation allowance on our U.S. and Canadian net deferred tax assets.

Net income. Our net income was approximately $131.6 million for the year ended December 31, 2012, as compared to $3.9 million for the year ended December 31, 2011. Our net income for the year ended December 31, 2012 was positively impacted by our gain on commodity price risk management activities and increases in revenue. However, net income was negatively impacted by increased DD&A, G&A, interest expense, and income tax expense.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Oil sales revenues. Oil sales revenues increased by $85.5 million to $115.7 million for the year ended December 31, 2011 as compared to oil sales of $30.2 million for the year ended December 31, 2010. In 2011, our crude oil sales averaged 3,684 barrels per day. Our oil sales volume increased 211% to 1,344.5 thousand barrels in 2011 as compared to 432.3 MBbls in 2010. The volume increase is due to our ongoing Bakken development program. These increases are primarily due to bringing 15.5 net wells on to production in 2011 in addition to commodity price increases. The increased revenue from oil sales in 2011 is attributed to a $78.5 million positive impact due to increased volumes. Additionally, the average price we realized on the sale of our oil increased from $69.89 per barrel for the year ended December 31, 2010, to $86.05 for the year ended December 31, 2011 resulting in a positive impact of $7.0 million in revenue. Overall, 92% of the increase is oil sales revenue was attributed to increased volumes and 8% was attributed to the increase in crude oil prices received.

Natural gas sales revenues. Natural gas revenues increased by $3.5 million to $4.3 million for the year ended December 31, 2011 as compared to natural gas revenues of $783,000 for the year ended December 31, 2010. Natural gas sales volumes increased by 360,000 Mcf to 523,000 Mcf for the year ended December 31, 2011. In 2011, our natural gas sales averaged 1,432 Mcf per day. The average price we realized on the sale of our natural gas was $8.22 per Mcf in 2011 compared to $4.81 per Mcf in 2010. The increase in natural gas prices realized resulted in a $500,000 increase in natural gas revenues and the increase in natural gas volumes resulted in a $3.0 million increase in natural gas revenues. Overall, 84% of the increase in natural gas sales revenue was attributed to increased volumes and 16% was attributed to the increase in natural gas prices received. The increase in our natural gas sales volumes is largely a result of production and sales of associated gas from our Bakken properties offset by a decline of our Wyoming assets that historically contributed a majority of our natural gas production. The price realized from sales of our natural gas increased due to the growth of our gas sales from our Bakken properties, which has a higher natural gas liquids content compared to our Wyoming properties. Although the majority of our gas from the Bakken wells-to-date has been flared, late in 2010, we began connecting our wells to third-party pipelines that gather and transport the gas to processing plants and sales pipelines. During 2011, we connected the majority of our wells to gas pipelines which allowed us to capture the related sales revenue.

Oil and gas production expense. Our oil and gas production expense increased by $20.1 million to $26.9 million for the year ended December 31, 2011, from $6.8 million for the same period in 2010. The increase is due to a $9.5 million increase in production taxes, a $9.2 million increase in lease operating expenses ("LOE"), and a $1.4 million increase in gathering, transportation and marketing expenses. The production tax increase is attributable to increased revenue as it is calculated as a fixed percentage of sales revenue. LOE increased year over year due to a higher number of wells that we operate or participate in. On a per unit basis, LOE increased from $7.03 per barrel sold in 2010 to $8.67 per barrel sold in 2011. As a result of the increase in the number of wells completed during 2011 compared to 2010, we incurred more expense in water disposal costs. The largest cost driver in our Williston Basin operations is the disposal of water used in the well completion operations. We expense the water handling costs once oil production is established. To date, the majority of water has been transported by truck to third party disposal facilities. In the fourth quarter 2011, we also incurred an expense of approximately $900,000 or $0.63 per barrel sold to relocate a third-party pipeline. Additionally, throughout 2011, we incurred additional costs to repair roads from the severe weather conditions that resulted in flooding during the spring of 2011.

Depletion, depreciation, amortization and abandonment liability accretion ("DD&A") expense. Our depletion, depreciation, amortization and abandonment liability accretion expense increased $23.8 million to $32.1 million for the year ended December 31, 2011, from $8.3 million for the same period in 2010. This increase is due to increased volumes sold in 2011 as sales increased by approximately 972,000 BOE. On a per unit basis, DD&A increased from $17.92 per BOE in 2010 to $22.40 per BOE in 2011. This increase is primarily due to the acquisition of proved reserves related to our 2010 and 2011 acquisitions. Acquired proved reserves are valued at fair market value on the date of acquisition, which contributes to a higher amortization base, as compared to our historical cost of acquiring leasehold and developing our properties. To date, the fair value of our acquired proved reserves has been higher than our historical cost of developing our properties even though the resulting EUR's are equivalent. Therefore, the increase in the ratio of costs subject to amortization to the reserves acquired is greater than our internally developed properties.

Additionally, well costs increased in 2011 as we began predominantly completing our wells using a greater number of fracture stimulation stages and increased volumes of proppant. These factors increased the well completion costs, but we believe that the higher upfront costs will generate overall higher returns through greater production volumes and total oil and gas reserves. Because of the early stages of development of our Bakken play, our reserves, especially for undeveloped locations, included increased well costs, but not the improved reserves.

General and administrative ("G&A") expense. G&A expense increased by $7.3 million to $19.5 million for the year ended December 31, 2011, from $12.2 million for the same period in 2010. This increase was due to growth in personnel and related costs as we expanded our operational activities. Total employees increased to 74 at year-end 2011 from 35 at year-end 2010. Additionally, in 2011, we incurred approximately $675,000 in transaction costs related to the acquisitions that closed in 2011 and early 2012, as compared to transaction costs of approximately $370,000 in 2010 for the acquisition that closed in 2010. On a per unit basis, G&A decreased from $26.53 per barrel sold in 2010 to $13.62 per barrel sold in 2011. The decrease is primarily due to our increase in sales volumes from our ongoing Bakken development program.

Our G&A expense includes the non-cash expense for stock-based compensation for stock options and share grants under our 2007 Stock Incentive Plan. For the year ended December 31, 2011, this expense was $5.2 million as compared to $4.5 million in 2010.

Operating income. Our operating income was approximately $41.5 million for the year ended December 31, 2011, as compared to approximately $3.8 million for the same period in 2010. This 999% increase in operating income was attributable to our on-going successful completions of wells and the resulting increase in sales volumes in our Bakken play as well as crude oil price improvement for the year ended 2011 as compared to 2010.

Loss on commodity price risk management activities. For the year ended December 31, 2011, we incurred a total loss on our risk management activities of $20.1 million. This loss is a result of our hedging program used to mitigate our exposure to commodity price fluctuations. This loss was comprised of approximately $3.9 million of realized losses for transactions that were settled during 2011 and $16.2 million of unrealized losses for the mark-to-market of forward transactions. The unrealized loss is a non-cash adjustment for the value of our risk management transactions at December 31, 2011. These transactions will continue to change in value until the transactions are settled and we will likely add to our hedging program. Therefore, we expect our net income to reflect the volatility of commodity price forward markets. Our cash flows will only be affected upon settlement of the transactions at the current market prices at that time.

Interest income (expense), net. For the year ended December 31, 2011, we recognized interest expense of approximately $19.0 million, as compared to $82,000 for the same period in 2010. Included in interest expense in 2011 was approximately $11.5 million of financing costs related to a stand-by bridge financing that we obtained to enable the closing of January 2012 Acquisition in the event that we were unable to fund the acquisition with proceeds from the issuance of the Original 2019 Notes in November 2011. As the bridge financing was not utilized, all financing costs of approximately $11.5 million were expensed in the fourth quarter of 2011. Also during 2011, as a result of the extinguishment of the second lien credit agreement in January 2012, we accelerated amortization of the related capitalized deferred financing costs, which resulted in additional amortization expense of approximately $2.4 million.

We recognized interest expense during 2011 of approximately $4.0 million related to the credit facilities and the issuance of the Original 2019 Notes in November 2011. Additionally, we capitalized interest costs of $8.4 million and $470,000 for the years ended December 31, 2011 and 2010, respectively.

Net income. Our net income was approximately $3.9 million for the year ended December 31, 2011, as compared to a net loss of $2.4 million for 2010. Although our revenue, net of production expenses, was higher compared to 2010, our 2011 net income was negatively impacted by increased DD&A, G&A, interest expense and, most significantly, the loss on price risk management activities discussed above.

Financial Instruments and Other Instruments

As of December 31, 2012, our financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable, commodity derivative instruments (see *Note 7—Commodity Derivative Instruments* under Item 8 of this Annual Report) and long-term debt (See *Note 5—Long-Term Debt* under Item 8 of this Annual Report). The carrying values of cash equivalents, accounts receivable, and accounts payable are representative of their fair values due to their short-term maturities. The carrying amount of our credit facility approximates fair value as it bears interest at variable rates over the term of the loan. Please refer to *Note 9—Fair Value Measurements* under Item 8 of this Annual Report for further discussion on the fair value of our 2019 Notes. Our management believes that we are not exposed to significant interest, currency or credit risks arising from these financial instruments.

Research and Development

As an exploration and production natural resource company, we do not normally engage in research and development ("R&D"). There were no R&D activities, or R&D expenditures made in the last three fiscal years.

Off-balance sheet arrangements

We have no off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Contractual Obligations and Commitments

The following table lists as of December 31, 2012, information with respect to our known contractual obligations:

	Payments due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(In thousands)		
Contractual Obligations					
Office Leases (a)	$ 3,420	$ 880	$ 1,770	$ 770	$ —
Drilling Rigs Obligations (b)	32,030	19,420	12,610	—	—
Pressure Pumping Services Obligation (c)	24,000	24,000	—	—	—
Credit Facility (d)	323,920	7,545	15,089	301,286	—
2019 Notes and Interest Payable (e)	1,254,985	64,985	130,000	130,000	930,000
Total	$ 1,638,355	$ 116,830	$ 159,469	$ 432,056	$ 930,000

(a) We lease office space in Denver, Colorado and Williston and Dickinson, North Dakota under separate operating lease agreements. The Denver, Colorado lease expires on October 31, 2016. The Williston and Dickinson, North Dakota leases expire on May 31, 2013 and December 31, 2014 respectively. Total rental commitments under non-cancelable leases for office space were $3.4 million at December 31, 2012.

(b) As of December 31, 2012 we had six drilling rig contracts under long term contracts, of which five of the contracts expire in 2013 and one expires in 2015. In the event of all of these contracts had been terminated early as of December 31, 2012, the Company would have been obligated to pay an aggregate amount of approximately $32.0 million as of December 31, 2012 under the varying terms of such contracts.

(c) As of December 31, 2012, we had a commitment with a pressure pumping service company providing a 24 hour per day crew availability, which expires December 31, 2013. In the event of early contract termination, the Company would be obligated to pay approximately $24.0 million as of December 31, 2012.

(d) Calculated based on our December 31, 2012 outstanding borrowings under our credit facility of $295.0 million and assumes no principal repayment until the maturity date on October 28, 2016. Interest on the revolving loans is payable at one of the following two variable rates: the alternate base rate for ABR loans or the adjusted LIBO rate for eurodollar loans, as selected by the Company, plus an additional percentage that can vary on a daily basis and is based on the daily unused portion of the facility. This additional percentage is referred to as the "Applicable Margin" and varies depending on the type of loan. The Applicable Margin for the ABR loans is a sliding scale of

0.75% to 1.75%, depending on borrowing base usage. The Applicable Margin on the adjusted LIBO rate is a sliding scale of 1.75% to 2.75%, depending on borrowing base usage. Additionally, the credit facility provides for a borrowing base fee of 0.5% and a commitment fee of 0.375% to 0.50%, depending on borrowing base usage. Cash interest expense on the credit facility is estimated assuming no principal repayment until the maturity date and a fixed interest rate of 2.47% (our all in rate on the credit facility as of December 31, 2012). For further discussion regarding the terms of the credit facility please refer to *Note 5—Long-Term Debt* under Item 8 in this Annual Report.

(e) Calculated based on our December 31, 2012 outstanding aggregate principal amount of $800.0 million of 8.125% 2019 Notes due December 1, 2019. The interest on the 2019 Notes is payable on June and December 1 of each year. Additionally, in January 2013, we issued the 2021 Notes in the aggregate principal amount of $350.0 million, which bear an annual interest of 5.50%. For purposes of the above calculation, the 2021 Notes were not included. For further discussion regarding the terms of the Senior Notes please refer to *Note 5—Long-Term Debt* under Item 8 in this Annual Report.

The above contractual obligations schedule does not include future anticipated settlement of derivative contracts or estimated amounts expected to be incurred in the future associated with the abandonment of our oil and gas properties, as we cannot determine with accuracy the timing of such payments.

As is customary in the oil and gas industry, the Company may at times have commitments in place to reserve or earn certain acreage positions or wells. If the Company does not meet such commitments, the acreage positions or wells may be lost.

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with generally accepted accounting principles in the United States, or GAAP, requires our management to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements and the reported amounts of revenues and expenses during the reporting period. The following is a summary of the significant accounting policies and related estimates that affect our financial disclosures. Actual results may differ from these estimates under different assumptions or conditions. For a detailed summary of our significant accounting policies, please refer to *Note 2—Basis of Presentation and Significant Accounting Policies* under Item 8 of this Annual Report. The following is a summary of the significant accounting policies and related estimates that affect our financial disclosures.

Oil and Natural Gas Reserves Estimates

Estimating accumulations of gas and oil is complex and is not exact because of the numerous uncertainties inherent in the process. The process relies on interpretations of available geological, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of the quality and quantity of available data; the interpretation of that data; the accuracy of various mandated economic assumptions; and the judgment of the persons preparing the estimate.

We believe estimated reserve quantities and the related estimates of future net cash flows are the most important estimates made by an exploration and production company such as ours because they affect the perceived value of our Company, are used in comparative financial analysis ratios, and are used as the basis for the most significant accounting estimates in our financial statements, including the quarterly calculation of depletion, depreciation and impairment of our proved oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil and natural gas, that geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. We determine anticipated future cash inflows and future production and development costs by applying benchmark prices and costs, including transportation, quality and basis differentials, in effect at the end of each quarter to the estimated quantities of oil and natural gas remaining to be produced as of the end of that quarter. We reduce expected cash flows to present value using a discount rate that depends upon the purpose for which the reserve estimates will be used. For example, the standardized measure calculation required by ASC Topic 932, Extractive Activities—Oil and Gas, requires us to apply a 10% discount rate. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established proved producing oil and natural gas properties, we make considerable effort to estimate our reserves, including through the use of independent reserves engineering consultants. We expect that quarterly reserve estimates will change in the future as additional information becomes available or as oil and natural gas prices and operating and capital costs change. We evaluate and estimate our oil and natural gas reserves as of December 31 of each year and quarterly throughout the year. For purposes of depletion, depreciation, and impairment, we adjust reserve quantities at all quarterly periods for the estimated impact of acquisitions and dispositions. Changes in depletion, depreciation or impairment calculations caused by changes in reserve quantities or net cash flows are recorded in the period in which the reserves or net cash flow estimate changes.

Oil and Natural Gas Properties, Depletion and Full Cost Ceiling Test

We follow the full cost method of accounting for oil and natural gas properties. Under this method, all productive and nonproductive costs incurred in connection with the acquisition of, exploration for and exploitation and development of oil and natural gas reserves are capitalized. Such capitalized costs include costs associated with lease acquisition, geological and geophysical work, delay rentals, drilling, completing and equipping oil and natural gas wells, and salaries, benefits and other internal salary related costs directly attributable to these activities. Proceeds from the disposition of oil and natural gas properties are generally accounted for as a reduction in capitalized costs, with no gain or loss recognized.

Depletion of the capitalized costs of oil and natural gas properties, including estimated future development costs, is provided for using the equivalent unit-of-production method based upon estimates of proved oil and natural gas reserves on a quarterly basis. The capitalized costs are amortized over the life of the reserves associated with the assets, with the amortization being expensed as depletion in the period that the reserves are produced. This depletion expense is calculated by dividing the period's production volumes by the estimated volume of reserves associated with the investment and multiplying the calculated percentage by the sum of the capitalized investment and estimated future development costs associated with the investment. Changes in our reserve estimates will therefore result in changes in our depletion expense per unit. Costs associated with production and general corporate activities are expensed in the period incurred. Unproved property costs not subject to amortization consist primarily of leasehold and seismic costs related to unproved areas. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. We will continue to evaluate these properties and costs will be transferred into the amortization base as undeveloped areas are tested. Unproved oil and natural gas properties are not amortized but are assessed, at least annually, for impairment either individually or on an aggregated basis to determine whether we are still actively pursuing the project and whether the project has been proven, either to have economic quantities of reserves or that economic quantities of reserves do not exist.

Under the full cost method of accounting, capitalized oil and gas property costs less accumulated depletion and net of deferred income taxes may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves plus the cost of unproved properties not subject to amortization (without regard to estimates of fair value), or estimated fair value, if lower, of unproved properties that are subject to amortization. Should capitalized costs exceed this ceiling, impairment would be recognized.

Derivative Instruments

The Company has entered into commodity derivative instruments, primarily utilizing swaps or "no premium" collars to reduce the effect of price changes on a portion of our future oil production. The Company's commodity derivative instruments are measured at fair value and are included in the accompanying balance sheets as commodity price risk management assets and liabilities. Unrealized gains and losses are recorded based on the changes in the fair values of the derivative instruments. Both the unrealized and realized gains and losses resulting from the contract settlement of derivatives are recorded in the commodity price risk management activities line on the consolidated statement of income. We value our derivative instruments by obtaining independent market quotes, as well as using industry-standard models that consider various assumptions, including quoted forward prices for commodities, risk free interest rates, and estimated volatility factors, as well as other relevant economic measures. The discount rate used in the fair values of these instruments includes a measure of nonperformance risk by the counterparty or us, as appropriate. We utilize the counterparties' valuations to assess the reasonableness of our valuations. The consideration of the factors results in an estimated exit-price for each derivative asset or liability under a market place participant's view. Management believes that this approach provides a reasonable, non-biased, verifiable, and consistent methodology for valuing commodity derivative instruments. For additional discussion, please refer to *Note 7—Commodity Derivative Instruments* under Item 8 of this Annual Report.

Business Combinations

We have accounted for all of our business combinations to date using the purchase method, which is the only method permitted under FASB ASC Topic 805, *Business Combinations*, and involves the use of significant judgment. The Company adopted the updated guidance of ASC 805 effective January 1, 2009 and applied it to our November 2010 acquisition, June 2011 acquisition, October 2011 acquisition and our January 2012 Acquisition. For a detailed summary of our acquisitions accounted for under ASC 805, please refer to *Note 4—Acquisitions* under Item 8 of this Annual Report.

Under the purchase method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the cost of an acquired entity, if any, over the net amounts assigned to assets acquired and liabilities assumed is recognized as goodwill. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, is recognized immediately to earnings as a gain from bargain purchase.

Determining the fair values of the assets and liabilities acquired involves the use of judgment, since some of the assets and liabilities acquired do not have fair values that are readily determinable. Different techniques may be used to determine fair values, including market prices (where available), appraisals, comparisons to transactions for similar assets and liabilities, and present value of estimated future cash flows, among others. Since these estimates involve the use of significant judgment, they can change as new information becomes available.

Each of the business combinations completed during the last three years consisted of oil and gas properties. The consideration we have paid to acquire these properties was entirely allocated to the fair value of the assets acquired and liabilities assumed at the time of acquisition. Consequently, there was no goodwill nor any bargain purchase gains recognized on any of our business combinations.

Asset Retirement Obligations

We are required to recognize an estimated liability for future costs associated with the abandonment of our oil and gas properties including without limitation the costs of reclamation of our drilling sites, storage and transmission facilities and access roads. We base our estimate of the liability on the industry experience of our management and on our current understanding of federal and state regulatory requirements. Our present value calculations require us to estimate the economic lives of our properties, assume what future inflation rates apply to external estimates and determine the credit-adjusted risk-free rate to use. In periods subsequent to the initial measurement of the asset retirement obligation ("ARO"), we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A over the life of the oil and gas property.

Income Tax Expense

Income taxes reflect the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income tax assets and liabilities represent the future tax return consequences of those differences, which will either be taxable or deductible when assets are recovered or settled. Deferred income taxes are also recognized for tax credits that are available to offset future income taxes. Deferred income taxes are measured by applying current tax rates to the differences between financial statement and income tax reporting. In assessing the need for a valuation allowance on our deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon whether future book income is sufficient to reverse existing temporary differences that give rise to deferred tax assets, as well as whether future taxable income is sufficient to utilize net operating loss and credit carryforwards. Assessing the need for, or the sufficiency of, a valuation allowance requires the evaluation of all available evidence, both negative and positive. For additional discussion, please refer to *Note 6—Income Taxes* under Item 8 of this Annual Report.

Revenue Recognition

Our revenue recognition policy is significant because revenue is a key component of our results of operations and of the forward-looking statements contained in our analysis of liquidity and capital resources. We derive our revenue primarily from the sale of crude oil and natural gas. We report revenue as the gross amounts we receive before taking into account production taxes and transportation costs, which are reported as separate expenses. We record revenue in the month our production is delivered to the purchaser, but payment is generally received 30 to 90 days after the date of production. At the end of each month, we make estimates of the amount of production that we delivered to the purchaser and the price we will receive. We record the variances between our estimates and the actual amounts we receive in the month payment is received.

Stock-Based Compensation

We have a stock-based compensation plan that includes restricted stock shares, restricted stock units ("RSUs"), performance awards, stock awards, and stock options issued to employees, officers and directors as more fully described in *Note 11—Share-Based Payments* under Item 8 of this Annual Report. We record expense associated with the fair value of stock-based compensation in accordance with ASC 718, *Stock Based Compensation*. We record compensation expense associated with the issuance of restricted stock shares and performance based RSUs based on the estimated fair value of these awards determined at the time of grant. The Company recognizes compensation cost for performance based grants on a tranche level basis over the requisite service period for the entire award. Each quarter, the Company evaluates the actual performance results compared to the performance metrics and estimates the probability of the metrics being satisfied. The Company adjusts the number of shares expected to be granted and related expense based on its assessment.

PV-10

The pre-tax present value of future net cash flows, or PV-10, is a non-GAAP measure because it excludes income tax effects. Management believes that pre-tax cash flow amounts are useful for evaluative purposes since future income taxes, which are affected by a Company's unique tax position and strategies, can make after-tax amounts less comparable. We derive PV-10 based on the present value of estimated future revenues to be generated from the production of proved reserves, net of estimated production and future development costs and future plugging and abandonment costs, using the twelve-month arithmetic average of the first of the month prices without giving effect to hedging activities or future escalation, costs as of the date of estimate without future escalation, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion, amortization and impairment and income taxes, and discounted using an annual discount rate of 10%. The following table reconciles the standardized measure of future net cash flows to PV-10 as of the dates shown (in millions):

	For the Years Ended December 31,		
	2012	2011	2010
Standardized measure of discounted future net cash flows	$ 1,608.5	$ 660.0	$ 154.6
Add: Present value of future income tax discounted at 10%	310.6	190.7	6.6
PV-10	$ 1,919.1	$ 850.7	$ 161.2

Recently Issued Accounting Pronouncements

For further information on the effects of recently adopted accounting pronouncements and the potential effects of new accounting pronouncements, refer to the section titled *Recent Accounting Pronouncements* under *Note 2—Basis of Presentation and Significant Accounting Policies* under Item 8 of this Annual Report.

Effects of Pricing and Inflation

The demand for oil field products and services has increased in the Williston Basin beginning in 2010 and continued throughout 2011 and 2012. Typically, as prices for oil and natural gas increase, so do the associated costs. As oil and natural gas prices decline, we would expect associated costs to decline, however, there may be a lag or the changes may be disproportionate to the lower prices. Material changes in prices also impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, depletion expense, impairment assessments of oil and gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase, higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

This section provides information about derivative financial instruments we use to manage commodity price volatility. Due to the historical volatility of crude oil prices, we have implemented a hedging strategy aimed at reducing the variability of the prices we receive for our production and providing a minimum revenue stream. Currently, we enter into derivative transactions such as collars and fixed price swaps in order to hedge our exposure to changes in commodity prices. All contracts are settled with cash and do not require the delivery of a physical quantity to satisfy settlement. While this hedging strategy may result in us having lower revenues than we would have if we were unhedged in times of higher oil prices, management believes that the stabilization of prices and protection afforded us by providing a revenue floor on a portion of our production is beneficial. We may, from time to time, opportunistically restructure existing derivative contracts or enter into new transactions to effectively modify the terms of current contracts in order to improve the pricing parameters in existing contracts or realize the current value of our existing positions. We may use the proceeds from such transactions to secure additional contracts for periods in which we believe there is additional unmitigated commodity price risk or for other corporate purposes.

This section also provides information about our interest rate risk below.

Commodity Price Risk

Our primary market risk is market changes in oil and natural gas prices. The market prices for oil and natural gas have been highly volatile and are likely to continue to be highly volatile in the future, which will impact our prospective revenues from the sale of products or properties. Currently, we utilize swaps and "no premium" collars to reduce the effect of price changes on a portion of our future oil production. We do not enter into derivative instruments for trading purposes. All hedges are accounted for using mark-to-market accounting.

We use costless collars to establish floor and ceiling prices on our anticipated future oil production. We neither receive nor pay net premiums when we enter into these arrangements. These contracts are settled monthly. When the settlement price (the market price for oil or natural gas on the settlement date) for a period is above the ceiling price, we pay our counterparty. When the settlement price for a period is below the floor price, our counterparty is required to pay us.

We use swaps to fix the sales price for our anticipated future oil production. Upon settlement, we receive a fixed price for the hedged commodity and pay our counterparty a floating market price, as defined in each instrument. These instruments are settled monthly. When the floating price exceeds the fixed price for a contract month, we pay our counterparty. When the fixed price exceeds the floating price, our counterparty is required to make a payment to us.

The use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. Our wholly-owned subsidiary, Kodiak Oil & Gas (USA) Inc., is currently a party to derivative contracts with six counterparties, and the Company is a guarantor of Kodiak Oil & Gas (USA) Inc. The Company has netting arrangements with the counterparties that provide for the offset of payables against receivables from separate derivative arrangements with the counterparties in the event of contract termination. Although the instruments are valued using indices published by established exchanges, the instruments are traded directly with the counterparties. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement.

The objective of the Company's use of derivative financial instruments is to achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage its exposure to commodity price risk. While the use of these derivative instruments limits the downside risk of adverse price movements, these instruments may also limit the Company's ability to benefit from favorable price movements. The Company may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of the Company's existing positions.

The Company's commodity derivative contracts as of December 31, 2012 are summarized below:

Collars	Basis(1)	Quantity (Bbl/d)	Strike Price ($/Bbl)
Jan 1, 2013—Dec 31, 2013	NYMEX	500	$85.00 - $117.00
Jan 1, 2013—Dec 31, 2015	NYMEX	300 - 425	$85.00 - $102.75

Swaps	Basis(1)	Quantity (Bbl/d)	Swap Price ($/Bbl)
2013 Total/Average	NYMEX	12,105	$95.49
2014 Total/Average	NYMEX	2,800	$91.86
2015 Total/Average	NYMEX	1,625	$87.13

Subsequent to December 31, 2012, the Company entered into additional commodity derivative contracts as summarized below:

Swaps	Basis(1)	Quantity (Bbl/d)	Swap Price ($/Bbl)
2013 Total/Average	NYMEX	2,373	$95.41
2014 Total/Average	NYMEX	4,000	$93.12

(1) NYMEX refers to quoted prices on the New York Mercantile Exchange

We determine the estimated fair value of derivative instruments using a market approach based on several factors, including quoted market prices in active markets, quotes from third parties, the credit rating of each counterparty, and the Company's own credit rating. The Company also performs an internal valuation to ensure the reasonableness of third-party quotes. In consideration of counterparty credit risk, the Company assessed the possibility of whether the counterparty to the derivative would default by failing to make any contractually required payments. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions. For further details regarding our derivative contracts please refer to *Note 7—Commodity Derivative Instruments* under Item 8 in this Annual Report.

Interest Rate Risk

At December 31, 2012, we had $800.0 million outstanding under our 2019 Notes due December 1, 2019, all of which has fixed interest rate of 8.125%.

In addition, as of December 31, 2012, we had (i) $450.0 million available to us under our credit facility, of which, $295.0 million was drawn at year-end. The credit facility bears interest at variable rates. Assuming we had the maximum amount outstanding at December 31, 2012 under our credit facility of $450.0 million, a 1.0% increase in interest rates would result in additional annualized interest expense of $4.5 million.

For a detailed discussion of the foregoing credit arrangements, including a discussion of the applicable interest rates, please refer to *Note 5—Long-Term Debt* under Item 8 in this Annual Report.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of Kodiak Oil & Gas Corp.

We have audited the accompanying consolidated balance sheets of Kodiak Oil & Gas Corp. (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of operations, stockholders' equity, and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. 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 financial statements referred to above present fairly, in all material respects, the consolidated financial position of Kodiak Oil & Gas Corp. at December 31, 2012 and 2011, and the consolidated results of its operations and its cash flows for the years then ended, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Kodiak Oil & Gas Corp.'s internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2013 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Denver, Colorado
February 28, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Kodiak Oil & Gas Corp.

We have audited the accompanying consolidated statements of operations, stockholders' equity, and cash flows of Kodiak Oil & Gas Corp. and subsidiaries for the year ended December 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our 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. 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 audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the results of operations and cash flows of Kodiak Oil & Gas Corp. and subsidiaries for the year ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

Hein & Associates LLP

Denver, Colorado
March 3, 2011

KODIAK OIL & GAS CORP.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December 31, 2012	December 31, 2011
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 24,060	$ 81,604
Cash held in escrow	—	12,194
Accounts receivable		
Trade	35,565	28,835
Accrued sales revenues	59,875	21,974
Commodity price risk management asset	10,864	—
Inventory, prepaid expenses and other	17,210	24,294
Total Current Assets	147,574	168,901
Oil and gas properties (full cost method), at cost:		
Proved oil and gas properties	2,007,442	641,532
Unproved oil and gas properties	457,888	298,500
Equipment and facilities	20,954	11,186
Less-accumulated depletion, depreciation, amortization, and accretion	(290,094)	(135,586)
Net oil and gas properties	2,196,190	815,632
Cash held in escrow	—	691,764
Commodity price risk management asset	2,850	—
Property and equipment, net of accumulated depreciation of $1,113 at December 31, 2012 and $618 at December 31, 2011	1,846	1,276
Deferred financing costs, net of amortization of $17,995 at December 31, 2012 and $15,029 at December 31, 2011	25,176	21,904
Total Assets	$ 2,373,636	$ 1,699,477
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 190,596	$ 78,402
Accrued interest payable	6,090	5,808
Commodity price risk management liability	304	11,925
Total Current Liabilities	196,990	96,135
Noncurrent Liabilities:		
Credit facilities	295,000	100,000
Senior notes, net of accumulated amortization of bond premium of $378 at December 31, 2012 and $0 at December 31, 2011	805,622	650,000
Commodity price risk management liability	4,288	10,035
Deferred tax liability, net	26,800	—
Asset retirement obligations	9,064	3,627
Total Noncurrent Liabilities	1,140,774	763,662
Total Liabilities	1,337,764	859,797
Commitments and Contingencies—Note 14	—	—
Stockholders' Equity:		
Common stock—no par value; unlimited authorized		
Issued and outstanding: 265,273,314 shares as of December 31, 2012 and 257,987,413 shares as of December 31, 2011	1,008,678	944,070
Retained earnings (accumulated deficit)	27,194	(104,390)
Total Stockholders' Equity	1,035,872	839,680
Total Liabilities and Stockholders' Equity	$ 2,373,636	$ 1,699,477

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF THESE CONSOLIDATED FINANCIAL STATEMENTS

KODIAK OIL & GAS CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except share data)

	For the Years Ended December 31, 2012	2011	2010
Revenues:			
Oil sales	$ 390,425	$ 115,692	$ 30,212
Gas sales	18,265	4,294	783
Total revenues	408,690	119,986	30,995
Operating expenses:			
Oil and gas production	85,498	26,885	6,795
Depletion, depreciation, amortization and accretion	155,634	32,068	8,234
General and administrative	34,528	19,495	12,190
Total operating expenses	275,660	78,448	27,219
Operating income	133,030	41,538	3,776
Other income (expense):			
Gain (loss) on commodity price risk management activities	44,602	(20,114)	(6,146)
Interest income (expense), net	(22,911)	(18,887)	(39)
Other income	3,663	1,338	7
Total other income (expense)	25,354	(37,663)	(6,178)
Income (loss) before income taxes	158,384	3,875	(2,402)
Income tax expense	26,800	—	—
Net income (loss)	$ 131,584	$ 3,875	$ (2,402)
Net income (loss) per common share:			
Basic	$ 0.50	$ 0.02	$ (0.02)
Diluted	$ 0.49	$ 0.02	$ (0.02)
Weighted average common shares outstanding:			
Basic	263,531,408	197,579,298	131,444,440
Diluted	267,671,296	200,551,992	131,444,440

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONSOLIDATED FINANCIAL STATEMENTS

KODIAK OIL & GAS CORP.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands)

	Common Stock Shares	Common Stock	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
Balance January 1, 2010:	118,880	$ 175,791	$ (105,863)	$ 69,928
Issuance of stocks for cash:				
—pursuant to equity offering	57,500	237,188	—	237,188
—pursuant to exercise of options	1,688	3,236	—	3,236
Share issuance costs	—	(12,758)	—	(12,758)
Restricted stock issued	100	261	—	261
Stock-based compensation	—	3,594	—	3,594
Net loss	—	—	(2,402)	(2,402)
Balance December 31, 2010:	178,168	$ 407,312	$ (108,265)	$ 299,047
Issuance of stocks for cash:				
—pursuant to equity offering	75,900	542,685	—	542,685
—pursuant to exercise of options	995	1,305	—	1,305
Shares issued in connection with acquisition	2,500	14,425	—	14,425
Share issuance costs	—	(27,450)	—	(27,450)
Restricted stock issued	424	593	—	593
Stock-based compensation	—	5,200	—	5,200
Net income	—	—	3,875	3,875
Balance December 31, 2011:	257,987	$ 944,070	$ (104,390)	$ 839,680
Issuance of stocks for cash:				
—pursuant to equity offering	—	—	—	—
—pursuant to exercise of options	1,425	3,654	—	3,654
Shares issued in connection with acquisition	5,056	49,798	—	49,798
Share issuance costs	—	—	—	—
Restricted stock issued	805	—	—	—
Stock-based compensation	—	11,156	—	11,156
Net income	—	—	131,584	131,584
Balance December 31, 2012:	265,273	$ 1,008,678	$ 27,194	$ 1,035,872

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONSOLIDATED FINANCIAL STATEMENTS

KODIAK OIL & GAS CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the Years Ended December 31,		
	2012	2011	2010
Cash flows from operating activities:			
Net income (loss)	$ 131,584	$ 3,875	$ (2,402)
Reconciliation of net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, amortization and accretion	155,634	32,068	8,234
Amortization of deferred financing costs and debt premium	2,588	15,029	83
Unrealized (gain) loss on commodity price risk management activities, net	(31,082)	16,217	5,743
Stock-based compensation	11,156	5,200	4,456
Deferred income taxes	26,800	—	—
Changes in current assets and liabilities:			
Accounts receivable-trade	(5,540)	(17,507)	(8,765)
Accounts receivable-accrued sales revenue	(37,901)	(17,396)	(2,668)
Prepaid expenses and other	6,465	(2,082)	(544)
Accounts payable and accrued liabilities	9,350	13,075	5,804
Accrued interest payable	282	5,434	374
Cash held in escrow	3,343	—	—
Net cash provided by operating activities	272,679	53,913	10,315
Cash flows from investing activities:			
Acquired oil and gas properties and facilities	(588,420)	(311,405)	(108,649)
Oil and gas properties	(753,609)	(232,360)	(69,891)
Sale of oil and gas properties	2,752	3,264	—
Equipment, facilities and other	(10,176)	(4,758)	(2,691)
Tubular goods	(28,625)	(15,490)	(18,778)
Cash held in escrow	30,000	(30,000)	—
Net cash used in investing activities	(1,348,078)	(590,749)	(200,009)
Cash flows from financing activities:			
Borrowings under credit facilities	380,000	350,808	97,308
Repayments under credit facilities	(185,000)	(290,808)	(57,308)
Proceeds from the issuance of senior notes	156,000	650,000	—
Proceeds from the issuance of common shares	2,609	543,990	240,424
Cash held in escrow	670,615	(673,958)	—
Debt and share issuance costs	(6,369)	(62,790)	(14,417)
Net cash provided by financing activities	1,017,855	517,242	266,007
Increase (decrease) in cash and cash equivalents	(57,544)	(19,594)	76,313
Cash and cash equivalents at beginning of the period	81,604	101,198	24,885
Cash and cash equivalents at end of the period	$ 24,060	$ 81,604	$ 101,198
Supplemental cash flow information:			
Oil & gas property accrual included in accounts payable and accrued liabilities	$ 155,385	$ 52,541	$ 9,426
Oil & gas property acquired through common stock	$ 49,798	$ 14,425	$ —
Cash paid for interest	$ 66,095	$ 6,898	$ 176
Cash paid for income taxes	$ —	$ —	$ —

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONSOLIDATED FINANCIAL STATEMENTS

KODIAK OIL & GAS CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Organization

Description of Operations

Kodiak Oil & Gas Corp. and its subsidiary ("Kodiak" or the "Company") is a public company listed for trading on the New York Stock Exchange under the symbol: "KOG". The Company's corporate headquarters are located in Denver, Colorado, USA. The Company is an independent energy company engaged in the exploration, exploitation, development, acquisition and production of crude oil and natural gas entirely in the Rocky Mountain region of the United States.

Kodiak Oil & Gas Corp. was incorporated (continued) in the Yukon Territory on September 28, 2001.

Note 2—Basis of Presentation and Significant Accounting Policies

Basis of Presentation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiary, Kodiak Oil & Gas (USA) Inc., a Colorado corporation. All significant inter-company balances and transactions have been eliminated in consolidation. The Company's business is transacted in US dollars and, accordingly, the financial statements are expressed in US dollars. The financial statements included herein were prepared from the records of the Company in accordance with generally accepted accounting principles in the United States ("GAAP"). In the opinion of management, all adjustments, consisting primarily of normal recurring accruals that are considered necessary for a fair presentation of the consolidated financial information, have been included.

Use of Estimates in the Preparation of Financial Statements

The preparation of the financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant areas requiring the use of assumptions, judgments and estimates include (1) oil and gas reserves; (2) cash flow estimates used in ceiling test of oil and natural gas properties; (3) depreciation, depletion and amortization; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations; (6) accrued revenue and related receivables; (7) valuation of commodity derivative instruments; (8) accrued liabilities; (9) valuation of share-based payments and (10) income taxes. Although management believes these estimates are reasonable, actual results could differ from these estimates. The Company evaluates its estimates on an on-going basis and bases its estimates on historical experience and on various other assumptions the Company believes to be reasonable under the circumstances. Although actual results may differ from these estimates under different assumptions or conditions, the Company believes its estimates are reasonable.

Reclassifications

The Company has condensed certain line items within the current period financial statements, and certain prior period balances were reclassified to conform to the current year presentation accordingly. Such reclassifications had no impact on net income, statements of cash flows, working capital or equity previously reported.

Cash and Cash Equivalents

Cash and cash equivalents consist of all highly liquid investments that are readily convertible into cash and have original maturities of three months or less when purchased. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments.

Cash Held In Escrow

As of December 31, 2011, the Company had approximately $704.0 million in cash held in escrow, $691.8 million was classified as a non-current asset and $12.2 million classified as a current asset. In January 2012, all of the funds being held in escrow at December 31, 2011, were released and used to fund the purchase price of the January 2012 Acquisition, repay all borrowings under the Company's second lien credit agreement and general corporate purposes. There was no cash held in escrow as of December 31, 2012.

Accounts Receivable

The Company records estimated oil and gas revenue receivable from third parties at its net revenue interest. The Company also reflects costs incurred on behalf of joint interest partners in accounts receivable. Management periodically reviews accounts receivable amounts for collectability and records its allowance for uncollectible receivables under the specific identification method. The Company did not record any allowance for uncollectible receivables in 2012, 2011, or 2010.

Concentration of Credit Risk

The Company's cash and cash equivalents and cash held in escrow are exposed to concentrations of credit risk. The Company manages and controls this risk by investing these funds with major financial institutions. The Company often has balances in excess of the federally insured limits.

The Company's receivables are comprised of oil and gas revenue receivables and joint interest billings receivable. The amounts are due from a limited number of entities. Therefore, the collectability is dependent upon the general economic conditions of the few purchasers and joint interest owners. The receivables are not collateralized. However, to date the Company has had minimal bad debts.

The Company's commodity derivative contracts are currently with six counterparties. Five of the six counterparties to the derivative instruments are highly rated entities with corporate ratings at or exceeding A– and A2 classifications by Standard & Poor's and Moody's, respectively. One counterparty had a corporate rating of BBB+ and Baa1by Standard & Poor's and Moody's, respectively.

Significant Customers

During the year ended December 31, 2012, 60% of the Company's production was sold to three customers. However, the Company does not believe that the loss of a single purchaser, including these three, would materially affect the Company's business because there are numerous other purchasers in the area in which the Company sells its production. For the years ended December 31, 2012, 2011 and 2010 purchases by the following companies exceeded 10% of the total oil and gas revenues of the company.

	For the Years Ended December 31,		
	2012	**2011**	**2010**
Customer A	27%	27%	—%
Customer B	17%	—%	—%
Customer C	16%	2%	—%
Customer D	1%	11%	—%
Customer E	—%	25%	75%

Inventory, Prepaid Expenses and Other

Included in inventory, prepaid expenses and other are deposits made on orders of tubular goods required for the Company's drilling program. The cost basis of the tubular goods is depreciated as a component of oil and gas properties once the inventory is used in drilling operations. The Company records tubular goods inventory and crude oil inventory at the lower of cost or market value. Inventory, prepaid expenses, and other are comprised of the following (in thousands):

	For the Years Ended December 31, 2012	2011
Well equipment inventory	$ 12,846	$ 12,700
Deposit on tubular goods	—	9,392
Crude oil inventory	2,388	706
Prepaid expenses	1,976	1,496
	$ 17,210	$ 24,294

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas operations whereby all costs related to the exploration and development of oil and gas properties are initially capitalized into a single cost center ("full cost pool"). Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling directly related to acquisition and exploration activities. Proceeds from property sales are generally credited to the full cost pool, with no gain or loss recognized, unless such a sale would significantly alter the relationship between capitalized costs and the proved reserves attributable to these costs. A significant alteration would typically involve a sale of 25% or more of the proved reserves related to a single full cost pool.

Depletion of capitalized costs of oil and gas properties is computed using the units-of-production method based upon estimated proved oil and gas reserves as determined by the Company's engineers and prepared by independent petroleum engineers. For this purpose, Kodiak converts its petroleum products and reserves to a common unit of measure. For depletion and depreciation purposes, relative volumes of oil and gas production and reserves are converted at the energy equivalent rate of six thousand cubic feet of natural gas to one barrel of crude oil. Costs included in the depletion base to be amortized include (a) all proved capitalized costs, less accumulated depletion, (b) estimated future development cost to be incurred in developing proved reserves; and (c) estimated dismantlement and abandonment costs, net of estimated salvage values, that have not been included as capitalized costs because they have not yet been capitalized as asset retirement costs. The costs of unproved properties are withheld from the depletion base until it is determined whether or not proved reserves can be assigned to the properties. The properties are reviewed quarterly for impairment. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion calculations.

Estimated reserve quantities and future net cash flows have the most significant impact on the Company. These estimates are also used in the quarterly calculations of depletion, depreciation and impairment of the Company's proved properties. Estimating accumulations of gas and oil is complex and is not exact because of the numerous uncertainties inherent in the process. For additional discussion on the process used to estimate oil and gas quantities please refer to *Note 15—Supplemental Oil and Gas Reserve Information (Unaudited).*

Impairment of Oil and Gas Properties

Under the full cost method of accounting, capitalized oil and gas property costs less accumulated depletion and net of deferred income taxes may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves plus the cost of unproved properties not subject to amortization (without regard to estimates of fair value), or estimated fair value, if lower, of unproved properties that are subject to amortization. Should capitalized costs exceed this ceiling, an impairment would be recognized.

There were no impairment charges recognized for the years ended December 31, 2012, 2011 and 2010.

Unproved Oil and Gas Properties

Unproved property costs not subject to amortization consist primarily of leasehold costs related to unproved areas. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. Interest costs related to significant unproved properties that are currently undergoing the activities necessary to get them ready for their intended use are capitalized to oil and gas properties. The Company's unproved properties are evaluated quarterly for the possibility of potential impairment. For the years ended December 31, 2012, 2011 and 2010 no impairment was recorded.

Equipment and Facilities

Equipment and facilities are recorded at cost. Depreciation is recorded using the straight-line method over the estimated useful lives of the related assets, ranging from one to twenty-five years.

Property and Equipment

Other property and equipment such as office furniture and equipment, vehicles, and computer hardware and software are recorded at cost. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed when incurred. Depreciation is recorded using the straight-line method over the estimated useful lives of three years for computer equipment, and five years for office equipment and vehicles. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts.

Deferred Financing Costs

Deferred financing costs include origination, legal, engineering, and other fees incurred to issue the debt in connection with the Company's credit facilities and Senior Notes. Deferred financing costs related to the Company's Senior Notes are amortized to interest expense using the effective interest method over the term of the debt. Deferred financing costs related to the credit facilities are amortized to interest expense on a straight-line basis over the respective borrowing term.

Commodity Derivative Instruments

The Company has entered into commodity derivative instruments, primarily utilizing swaps or "no premium" collars to reduce the effect of price changes on a portion of our future oil production. The Company's commodity derivative instruments are measured at fair value and are included in the accompanying balance sheets as commodity price risk management assets and liabilities. Unrealized gains and losses are recorded based on the changes in the fair values of the derivative instruments. Both the unrealized and realized gains and losses resulting from the contract settlement of derivatives are recorded in the commodity price risk management activities line on the consolidated statement of income. The Company's valuation estimate takes into consideration the counterparties' credit worthiness, the Company's credit worthiness, and the time value of money. The consideration of the factors results in an estimated exit-price for each derivative asset or liability under a market place participant's view. Management believes that this approach provides a reasonable, non-biased, verifiable, and consistent methodology for valuing commodity derivative instruments. For additional discussion on commodity derivative instruments please refer to *Note 7—Commodity Derivative Instruments.*

Fair Value of Financial Instruments

The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable, commodity derivative instruments (discussed above) and long-term debt. The carrying values of cash and cash equivalents, accounts receivable and accounts payable are representative of their fair values due to their short-term maturities. The carrying amount of the Company's credit facility approximates fair value as it bears interest at variable rates over the term of the loan. The Company's second lien credit agreement and its 2019 Notes are recorded at cost and the fair value is disclosed in *Note 9—Fair Value Measurements*. Considerable judgment is required to develop estimates of fair value. The estimates provided are not necessarily indicative of the amounts the Company would realize upon the sale or refinancing of such instruments.

Asset Retirement Obligation

The Company recognizes estimated liabilities for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time the Company makes the decision to complete the well or a well is acquired. For additional discussion on asset retirement obligations please refer to *Note 8—Asset Retirement Obligations.*

Revenue Recognition

The Company recognizes revenues from the sale of crude oil and natural gas using the sales method of accounting. Revenues from the sale of crude oil and natural gas are recognized when the product is delivered at a fixed or determinable price, title has transferred, and collectability is reasonably assured and evidenced by a contract. Additionally, there were no material imbalances at December 31, 2012, and December 31, 2011.

Share Based Payments

At December 31, 2012, the Company has a stock-based compensation plan that includes restricted stock shares, restricted stock units, performance awards, stock awards, and stock options issued to employees, officers and directors as more fully described in *Note 11—Shared-Based Payments*. The Company records expense associated with the fair value of stock-based compensation in accordance with ASC 718, *Stock Based Compensation*. The Company records compensation expense associated with the issuance of restricted stock shares and RSUs based on the estimated fair value of these awards determined at the time of grant.

Income Taxes

Deferred income tax assets and liabilities are recognized for the future income tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective income tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred income tax assets and liabilities of a change in income tax rates is recognized in income in the period that includes the enactment date. The measurement of deferred income tax assets is reduced, if necessary, by a valuation allowance if management believes that it is more likely than not that some portion or all of the net deferred tax assets will not be fully realized on future income tax returns. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, projected future taxable income and tax planning strategies in making this assessment.

The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement.

Recent Accounting Pronouncements

In May 2011, the FASB issued Accounting Standards Update 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS*. This update does not require additional fair value measurements and is not intended to establish valuation standards or affect valuation practices outside of financial reporting. This update may require certain additional disclosures related to fair value measurements. The Company does not expect the adoption of this update will materially impact its financial statement disclosures.

In December 2011, the FASB issued Accounting Standards Update 2011-11 ("ASU 2011-11"), *Balance Sheet: Disclosures about Offsetting Assets and Liabilities*. The objective of ASU 2011-11 is to require an entity to provide enhanced disclosures that will enable users of its financial statements to evaluate the effect or potential effect of netting arrangements on an entity's financial position. ASU 2011-11 is effective for interim and annual reporting periods beginning on or after January 1, 2013 and should be applied retrospectively. The adoption of this standard will not have an impact on the Company's financial position or results of operations, but will require enhanced disclosures regarding derivative instruments.

Other accounting standards that have been issued or proposed by the FASB, or other standards-setting bodies, that do not require adoption until a future date, are not expected to have a material impact on the financial statements upon adoption.

Note 3—Oil and Gas Properties

The Company's oil and gas properties are entirely within the United States. The net capitalized costs related to the Company's oil and gas producing activities were as follows (in thousands):

	For the Years Ended December 31,		
	2012	2011	2010
Proved oil and gas properties	$ 2,007,442	$ 641,532	$ 212,300
Unproved oil and gas properties (1)	457,888	298,500	121,732
Equipment and facilities	20,954	11,186	2,429
Total capitalized costs (2)	$ 2,486,284	$ 951,218	$ 336,461
Accumulated depletion, depreciation, amortization, and accretion	(290,094)	(135,586)	(103,799)
Net capitalized costs	$ 2,196,190	$ 815,632	$ 232,662

(1) Unproved oil and gas properties represent unevaluated costs the Company excludes from the amortization base until proved reserves are established or impairment is determined. The Company estimates that the remaining costs will be evaluated within 3 to 5 years.

(2) Includes capitalized interest of $54.9 million, $8.9 million, and $470,000 as of December 31, 2012, 2011, and 2010, respectively.

The following table presents information regarding the Company's net costs incurred in oil and natural gas property acquisition, exploration and development activities (in thousands):

	For the Years Ended December 31,		
	2012	2011	2010
Property Acquisition costs:			
Proved	$ 322,835	$ 152,538	$ 33,539
Unproved	330,912	182,878	95,572
Exploration costs	—	—	14,821
Development costs	874,303	274,293	52,081
Total	$ 1,528,050	$ 609,709	$ 196,013
Total excluding asset retirement obligation	$ 1,523,088	$ 608,102	$ 195,164

Depletion expense related to the proved properties per equivalent BOE of production for the years ended December 31, 2012, 2011 and 2010 were $29.62, $22.40 and $17.92, respectively (unaudited).

The following table sets forth a summary of oil and gas property costs, which substantially consists of acquisition costs, not being amortized as of December 31, 2012 by the year in which such costs were incurred (in thousands):

	Unproved Additions by Year
Prior	$ 642
2010	43,685
2011	100,576
2012	312,985
Total	$ 457,888

Note 4—Acquisitions

January 2012 Acquisition

On January 10, 2012, the Company acquired two separate private, unaffiliated oil and gas company's interests in approximately 50,000 net acres of Williston Basin leaseholds, and related producing properties located primarily in McKenzie and Williams Counties, North Dakota, along with various other related rights, permits, contracts, equipment and other assets, including the assignment and assumption of a drilling rig contract for a combination of cash and stock. The sellers received an aggregate of 5.1 million shares of Kodiak's common stock valued at approximately $49.8 million and cash consideration of approximately $588.4 million. The effective date for the acquisition was September 1, 2011, with purchase price adjustments calculated as of the closing date on January 10, 2012. The acquisition provided strategic additions adjacent to the Company's core project area and the acquired producing wells contributed revenue of $33.6 million and $0 to Kodiak for the years ended December 31, 2012 and 2011, respectively. Total transaction costs related to the acquisition were approximately $295,000, of which $85,000 and $210,000 were recorded in the statement of operations within the general and administrative expenses line item for the years ended December 31, 2012 and 2011, respectively. No material costs were incurred for the issuance of the 5.1 million shares of common stock.

The acquisition is accounted for using the acquisition method under ASC 805, *Business Combinations*, which requires the acquired assets and liabilities to be recorded at fair values as of the acquisition date of January 10, 2012. In July 2012, the Company completed the transaction's post-closing settlement. The following table summarizes the purchase price and final allocation of the fair value of assets acquired and liabilities assumed (in thousands):

Consideration Given		
Cash from senior notes	$	588,420
Kodiak Oil & Gas Corp. common stock (5,055,612 Shares)		49,798 *
Total consideration given	$	638,218
Allocation of Purchase Price		
Proved oil and gas properties		322,835
Unproved oil and gas properties		313,053
Equipment and facilities		7,025
Total fair value of oil and gas properties acquired	$	642,913
Working capital		(3,895)
Asset retirement obligation		(800)
Fair value of net assets acquired	$	638,218
Working capital acquired was estimated as follows:		
Accounts receivable		7,200
Prepaid completion costs		465
Crude oil inventory		540
Accrued liabilities		(8,300)
Suspense payable		(3,800)
Total working capital	$	(3,895)

* The fair value of the consideration attributed to the Common Stock under ASC 805 was based on the Company's closing stock price of $9.85 on the measurement date of January 10, 2012.

October 2011 Acquisition

On October 28, 2011, the Company acquired a private, unaffiliated oil and gas company's interests in approximately 13,400 net acres of Williston Basin leaseholds, and related producing properties located primarily in Williams County, North Dakota along with various other related rights, permits, contracts, equipment and other assets. The seller received cash consideration of approximately $248.2 million and the effective date was August 1, 2011, with purchase price adjustments calculated as of the closing date on October 28, 2011. The total purchase included approximately $239.9 million related to the acquisition of the properties and approximately $8.6 million related to the assumption of certain working capital items. The acquisition provided strategic additions adjacent to the Company's core project area and the acquired producing wells contributed revenue of $27.2 million and $5.6 million to Kodiak for the years ended December 31, 2012 and 2011, respectively. Total transaction costs related to the acquisition incurred were approximately $200,000, all of which was recorded in the statement of operations within the general and administrative expenses line item for the year ended December 31, 2011.

The acquisition is accounted for using the acquisition method under ASC 805, *Business Combinations*, which requires the acquired assets and liabilities to be recorded at fair values as of the acquisition date of October 28, 2011. In February 2012, the Company completed the transaction's post-closing settlement. The following table summarizes the purchase price and final allocation of the fair value of the assets acquired and liabilities assumed (in thousands):

Purchase Price		**October 28, 2011**
Consideration Given		
Cash	$	248,213
Total consideration given	$	248,213
Allocation of Purchase Price		
Proved oil and gas properties	$	149,738
Unproved oil and gas properties		90,161
Total fair value of oil and gas properties acquired		239,899
Working capital		8,552
Asset retirement obligation		(238)
Fair value of net assets acquired	$	248,213
Working capital acquired was estimated as follows:		
Accounts receivable	$	10,260
Prepaid drilling costs		755
Crude oil inventory		190
Well equipment inventory		1,324
Accrued liabilities		(1,247)
Suspense payable		(2,730)
Total working capital	$	8,552

June 2011 Acquisition

On June 30, 2011, the Company acquired a private, unaffiliated oil and gas company's interests in approximately 25,000 net acres of Williston Basin leaseholds and related producing properties located in McKenzie County, North Dakota along with various other related rights, permits, contracts, equipment and other assets for a combination of cash and stock. The seller received 2.5 million shares of Kodiak's common stock valued at approximately $14.4 million and cash consideration of approximately $71.5 million. The effective date for the acquisition was April 1, 2011, with purchase price adjustments calculated as of the closing date on June 30, 2011. The acquisition provided strategic additions to the Company's core positions in Koala, Smokey and Grizzly Project areas and the acquired producing wells contributed revenue to Kodiak of $1.5 million and $1.4 million for the years ended December 31, 2012 and 2011, respectively. Total transaction costs related to the acquisition were approximately $265,000, all of which were recorded in the statement of operations, within the general and administrative expenses line item, for the year ended December 31, 2011. Costs of $85,000 for issuing and registering with the SEC for the resale of 2.5 million shares of common stock were charged to common stock in 2011.

The acquisition is accounted for using the acquisition method under ASC 805, *Business Combinations*, which requires the acquired assets and liabilities to be recorded at fair values as of the acquisition date of June 30, 2011. The transaction's final settlement was completed in September 2011 resulting in no material changes. Of the $85.9 million purchase price, $8.0 million was allocated to proved oil and gas properties, $77.8 million was allocated to unproved oil and gas properties and the remaining $100,000 was working capital and asset retirement obligation adjustments.

November 2010 Acquisition

On November 30, 2010, the Company acquired a private, unaffiliated oil and gas company's interests in approximately 14,500 net acres of Williston Basin leaseholds and related producing properties primarily located in McKenzie County, North Dakota for total consideration of $108.6 million. The effective date for the acquisition was August 1, 2010, with purchase price adjustments calculated at the closing date on November 30, 2010. The acquisition provided contiguous leaseholds with approved drilling permits near the Company's existing acreage position.

The acquisition is accounted for using the acquisition method under ASC 805, *Business Combinations*, which requires the acquired assets and liabilities to be recorded at fair values as of the acquisition date of November 30, 2010. The transaction's final settlement was completed in April 2011 resulting in no material changes. Of the $108.6 million purchase price, $32.2 million was allocated to proved oil and gas properties, $77.2 million was allocated to unproved oil and gas properties and the remaining $800,000 was working capital deficit and asset retirement obligation adjustments.

Pro Forma Financial Information

For the years ended December 31, 2012 and 2011, the following pro forma financial information represents the combined results for the Company and the properties acquired in January 2012 as if the acquisition and related financing had occurred on January 1, 2011 and for the properties acquired in October 2011 and June 2011 as if these acquisitions and related financing had occurred on January 1, 2010. For the year ended December 31, 2010, the following pro forma financial information represents the combined results for the Company and the properties acquired in October 2011 and June 2011 as if these acquisitions and related financing had occurred on January 1, 2010, and for the properties acquired in November 2010 as if the acquisition and related financing had occurred on January 1, 2009 (all in thousands, except per share data). For purposes of the pro forma it was assumed that the Original 2019 Notes were used to fund the January 2012 Acquisition and that the stand-by bridge previously arranged was not utilized. Additionally, it was assumed that common stock was used to fund the October 2011, June 2011 and November 2010 acquisitions. The pro forma information includes the effects of adjustments for depletion, depreciation, amortization and accretion expense of $600,000, $27.7 million and $5.1 million and amortization of financing costs of $0, $1.5 million and $0 for the years ended December 31, 2012, 2011 and 2010, respectively. For the years ended December 31, 2012 and 2011 there were pro forma adjustments of $400,000 and $15.5 million reducing interest expense, respectively. The pro forma financial information includes total capitalization of interest expense of $46.4 million, $59.5 million and $470,000 for the years ended December 31, 2012, 2011 and 2010 respectively. For the year ended December 31, 2012 there was a pro forma adjustment of $500,000 to record income tax expense attributable to the pro forma income from the January 2012 Acquisition.

The pro forma results do not include any cost savings or other synergies that may result from the acquisitions or any estimated costs that have been or will be incurred by the Company to integrate the properties acquired. The pro forma results are not necessarily indicative of what actually would have occurred if the acquisitions had been completed as of the beginning of the period, nor are they necessarily indicative of future results.

	For the Years Ended December 31,		
	2012	2011	2010
Operating revenues	$ 410,490	$ 187,842	$ 40,350
Net income	$ 132,308	$ 43,714	$ 36
Net income per common share			
Basic	$ 0.50	$ 0.18	$ 0.00
Diluted	$ 0.49	$ 0.18	$ 0.00

Note 5—Long-Term Debt

As of the dates indicated the Company's long-term debt consisted of the following (in thousands):

	At December 31,	
	2012	2011
Credit Facility due October 2016	$ 295,000	$ —
Second Lien Credit Agreement due April 2017	—	100,000
2019 Notes due December 2019	800,000	650,000
Unamortized Premium on 2019 Notes	5,622	—
Total Long-Term Debt	$ 1,100,622	$ 750,000
Less: Current Portion of Long Term Debt	—	—
Total Long-Term Debt, Net of Current Portion	$ 1,100,622	$ 750,000

Credit Facility

Kodiak Oil & Gas (USA) Inc. (the "Borrower"), a wholly-owned subsidiary of Kodiak Oil & Gas Corp., has in place a credit facility with a syndicate of banks. The maximum credit available under the credit facility is $750.0 million with a borrowing base of $450.0 million. Redetermination of the borrowing base occurs semi-annually, on April 1 and October 1. Additionally, the Company may elect a redetermination of the borrowing base one time during any six month period. The credit facility matures on October 28, 2016.

Interest on the credit facility is payable at one of the following two variable rates: the alternate base rate for ABR loans or the adjusted LIBO rate for Eurodollar loans, as selected by the Company, plus an additional percentage that can vary on a daily basis and is based on the daily unused portion of the facility. This additional percentage is referred to as the "Applicable Margin" and varies depending on the type of loan. The Applicable Margin for the ABR loans is a sliding scale of 0.75% to 1.75%, depending on borrowing base usage. The Applicable Margin on the adjusted LIBO rate is a sliding scale of 1.75% to 2.75%, depending on borrowing base usage. Additionally, the credit facility provides for a borrowing base fee of 0.5% and a commitment fee of 0.375% to 0.50%, depending on borrowing base usage. The grid below shows the Applicable Margin options depending on the applicable Borrowing Base Utilization Percentage (as defined in the credit facility) as of December 31, 2012 and the date of this filing:

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	<25.0%	≥25.0% <50.0%	≥50.0% <75.0%	≥75.0% <90.0%	≥90.0%
Eurodollar Loans	1.75%	2.00%	2.25%	2.50%	2.75%
ABR Loans	0.75%	1.00%	1.25%	1.50%	1.75%
Commitment Fee Rate	0.375%	0.375%	0.50%	0.50%	0.50%

The credit facility contains representations, warranties, covenants, conditions and defaults customary for transactions of this type, including but not limited to: (i) limitations on liens and incurrence of debt covenants; (ii) limitations on dividends, distributions, redemptions and restricted payments covenants; (iii) limitations on investments, loans and advances covenants; and (iv) limitations on the sale of property, mergers, consolidations and other similar transactions covenants. Additionally, the credit facility requires the Borrower to enter hedging agreements necessary to support the borrowing base.

The credit facility also contains financial covenants requiring the Borrower to comply with a current ratio of consolidated current assets (including unused borrowing capacity) to consolidated current liabilities of not less than 1.0:1.0 and to maintain, on the last day of each quarter, a ratio of total debt to EBITDAX of not greater than (i) 4.75 to 1.0 at the end of each of the two fiscal quarters ending December 31, 2011 and March 31, 2012, (ii) 4.50 to 1.0 at the end of the fiscal quarter ending June 30, 2012, (iii) 4.25 to 1.0 at the end of the fiscal quarter ending September 30, 2012, and (iv) 4.0 to 1.0 at the end of each fiscal quarter thereafter. As of December 31, 2012, the Company was in compliance with all financial covenants under the credit facility.

As of December 31, 2012, the Company had $295.0 million in outstanding borrowings under the credit facility and as such, the available credit under the credit facility at that date was $155.0 million. Subsequent to December 31, 2012, the Company made additional borrowings and also used all of the net proceeds from the 2021 Notes in January 2013 (as further discussed below) to repay borrowings on the credit facility. The Company's outstanding balance as of the date of this filing under the credit facility is $50.0 million. Any borrowings under the credit facility are collateralized by the Borrower's oil and gas producing properties, the Borrower's personal property and the equity interests of the Borrower held by the Company. The Company has entered into crude oil hedging transactions with several counterparties that are also lenders under the credit facility. The Company's obligations under these hedging contracts are secured by the credit facility.

Second Lien Credit Agreement

On January 10, 2012, Kodiak Oil & Gas (USA) Inc. terminated the second lien credit agreement and repaid the $100.0 million of outstanding debt, and incurred a $3.0 million prepayment penalty in connection therewith. The Company recorded the $3.0 million prepayment penalty in the first quarter of 2012 within the interest income (expense), net line item of the statement of operations.

8.125% Senior Notes due 2019

In November 2011, the Company issued the Original 2019 Notes at par in the aggregate principal amount of $650.0 million and in May 2012, the Company issued an additional $150.0 million aggregate principal amount of the Follow-On 2019 Notes at a price of 104.0% of par. The 2019 Notes bear an annual interest rate of 8.125% and are due December 1, 2019. The interest on the 2019 Notes is payable on June and December 1 of each year. The proceeds received from the Original 2019 Notes were deposited into an escrow account, along with cash from our November equity offering in the amount of $674.0 million as of December 31, 2011. As discussed in *Note 4—Acquisitions*, in January 2012, the Company completed the January 2012 Acquisition and all funds were released from escrow. The Company received net proceeds of approximately $632.4 million after deducting discounts and fees. The net proceeds were used to repay all borrowings under the second lien credit agreement, to finance the January 2012 Acquisition and the remaining proceeds were used to fund capital expenditures. The net proceeds from the Follow-On 2019 Notes in the amount of $151.8 million, after deducting discounts and fees were used to repay all outstanding borrowings on the credit facility at that time and to fund the Company's ongoing capital expenditure program and general corporate purposes. The 2019 Notes were issued under an Indenture, dated as of November 23, 2011 (the "Indenture") among the Company, Kodiak Oil & Gas (USA) Inc. (the "Guarantor"), U.S. Bank National Association, as the trustee (the "Trustee") and Computershare Trust Company of Canada, as the Canadian trustee. The Indenture contains affirmative and negative covenants that, among other things, limit the Company's and the Guarantor's ability to make investments; incur additional indebtedness or issue preferred stock; create liens; sell assets; enter into agreements that restrict dividends or other payments by restricted subsidiaries; consolidate, merge or transfer all or substantially all of the assets of the Company; engage in transactions with the Company's affiliates; pay dividends or make other distributions on capital stock or prepay subordinated indebtedness; and create unrestricted subsidiaries. The Indenture also contains customary events of default. Upon the occurrence of events of default arising from certain events of bankruptcy or insolvency, the 2019 Notes shall become due and payable immediately without any declaration or other act of the Trustee or the holders of the 2019 Notes. Upon the occurrence of certain other events of default, the Trustee or the holders of the 2019 Notes may declare all outstanding 2019 Notes to be due and payable immediately. The Company was in compliance with all financial covenants under its 2019 Notes as of December 31, 2012, and through the filing of this report.

The 2019 Notes are redeemable by the Company at any time on or after December 1, 2015, at the redemption prices set forth in the Indenture. The 2019 Notes are redeemable by the Company prior to December 1, 2015, at the redemption prices plus a "make-whole" premium set forth in the Indenture. The Company is also entitled to redeem up to 35% of the aggregate principal amount of the 2019 Notes before December 1, 2014 with net proceeds that the Company raises in equity offerings at a redemption price equal to 108.125% of the principal amount of the 2019 Notes being redeemed, plus accrued and unpaid interest.

In connection with the sale of the 2019 Notes, the Company entered into registration rights agreements that provide the holders of the 2019 Notes certain rights relating to the registration of the 2019 Notes under the Securities Act. On July 20, 2012, the Company filed a registration statement on Form S-4 (No. 333-182783, amended on October 9, 2012 and declared effective by the SEC on October 11, 2012) with the SEC in accordance with such registration rights agreements. On October 12, 2012, the Company commenced such registered exchange offer. The exchange offer was completed on November 16, 2012.

5.50% Senior Notes due 2021

In January 2013, the Company issued at par $350.0 million of 5.50% Senior Notes due January 15, 2021. The Company received net proceeds of approximately $343.3 million after deducting discounts and fees. All of the net proceeds from the 2021 Notes were used to repay borrowings on the Company's credit facility. The interest on the 2021 Notes is payable on January 15 and July 15 of each year.

In connection with the sale of the 2021 Notes, the Company entered into a registration rights agreement pursuant to which it agreed (1) to file an exchange offer registration statement to allow the holders to exchange the 2021 Notes for SEC-registered notes and (2) to file, under certain circumstances, a shelf registration statement to cover resales of the 2021 Notes. If the Company fails to complete the registered exchange offer or the shelf registration statement has not been declared effective within specified time periods, the Company will be required to pay liquidated damages by way of additional interest on the 2021 Notes.

Deferred Financing Costs

As of December 31, 2012, the Company had deferred financing costs of $25.2 million related to its credit facility and Senior Notes. Deferred financing costs include origination, legal, engineering, and other fees incurred in connection with the Company's credit facility and Senior Notes. For the years ended December 31, 2012, 2011, and 2010, the Company recorded amortization expense of $3.0 million, $15.0 million, and $83,000, respectively.

Interest Incurred On Long-Term Debt

For the years ended December 31, 2012, 2011, and 2010, the Company incurred interest expense on long-term debt of $63.4 million, $12.4 million, and $549,000, respectively. Of the total interest incurred, the Company capitalized interest costs of $46.0 million, $8.4 million, and $470,000 for the years ended December 31, 2012, 2011, and 2010, respectively. Additionally, for the year ended December 31, 2012 interest expense was reduced for the amortization of the bond premium in the amount of $378,000.

Note 6— Income Taxes

The Company's income tax expense consists of the following (in thousands):

	For the Years Ended December 31,		
	2012	2011	2010
Current income tax expense (U.S. and Canada)	$ —	$ —	$ —
Deferred income tax expense			
U.S.	$ 26,800	$ —	$ —
Canada	—	—	—
Total deferred income tax expense	26,800	—	—
Total income tax expense	$ 26,800	$ —	$ —

Income tax expense differed from amounts that would result from applying the U.S. statutory income tax rate of 35% to income before income taxes as follows:

	For the Years Ended December 31,		
	2012	2011	2010
Federal	35.00%	35.00%	35.00%
State	2.43%	2.23%	2.70%
Other	2.51%	0.00%	(2.50)%
Change in valuation allowances	(23.00)%	(37.23)%	(35.20)%
Net	16.94%	0.00%	0.00%

The principal components of the Company's deferred income tax assets and liabilities are as follows (in thousands):

	For the Years Ended December 31,		
	2012	2011	2010
Deferred Income Tax Assets (Liabilities):			
U.S. net operating loss carryovers	$ 51,176	$ 40,378	$ 29,584
Stock-based compensation	5,988	5,225	5,138
Oil and gas properties	(79,369)	(17,543)	2,066
Canadian net operating losses and issuance costs	11,070	8,600	9,796
Derivatives (Mark to market)	(3,414)	8,175	2,200
Other	(1,181)	(645)	—
	(15,730)	44,190	48,784
Valuation allowance on United States tax assets	—	(35,590)	(38,988)
Valuation allowance on Canadian tax assets	(11,070)	(8,600)	(9,796)
Deferred income tax asset (liability), net	$ (26,800)	$ —	$ —

Through March 31, 2012, the Company had a full valuation allowance against both its U.S. and Canadian net deferred tax assets since it could not conclude that it was more likely than not that the net deferred tax assets would have been fully realized. This conclusion was based on the fact that the Company had not generated cumulative taxable income through March 31, 2012 and had incurred a cumulative book loss over the previous three fiscal years. However, during the second quarter of 2012, the Company concluded that it is more likely than not that it would be able to realize the benefits of its U.S. deferred tax assets, and that it was appropriate to release the U.S. valuation allowance against its U.S. deferred tax assets. This decision was based on the fact that for the three-year period ended June 30, 2012, the Company had reported positive cumulative net income. Additionally, for the three months ended June 30, 2012, the Company recognized income before taxes of $119.0 million. As a result of the second quarter 2012 income before income taxes, the Company was in a net deferred tax liability position as of June 30, 2012. As of December 31, 2012, the Company remained in a net deferred tax liability position.

The Company continues to provide a full valuation allowance on the Canadian net deferred tax assets as ultimate realization of these deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. At each reporting period, management considers the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, projected future taxable income and tax planning strategies in making this assessment. As the Company does not have revenue generating assets in Canada, the Company does not expect to utilize the Canadian net deferred tax assets. The Company will continue to evaluate whether a valuation allowance on a separate country basis is needed in future reporting periods.

Net Operating Losses

As of December 31, 2012, the Company has available a cumulative net operating loss ("NOL") of approximately $186.0 million which may be carried forward to reduce taxable income in future years. As of December 31, 2012, the Company had US NOL carryovers of $156.5 million for US federal income tax purposes and $136.7 million for financial reporting purposes. The difference of $19.8 million relates to tax deductions for compensation expense for financial reporting purposes for which the benefit will not be recognized until the related deductions reduce taxes payable. In addition, the Company has $29.5 million in NOLs related to its Canadian tax filings. The United States NOLs expire between 2023 and 2031 and the Canadian NOLs expire between 2014 and 2031. Substantially all of the Company's net income (loss) is generated in the United States.

The Tax Reform Act of 1986 contains provisions that limit the utilization of net operating loss carryforwards if there has been a change in ownership as described in Internal Revenue Code Section 382. The Company analyzed potential limitations under IRC Section 382 and determined there are no limitations to its net operating loss carryforwards as of December 31, 2012.

Accounting for Uncertainty in Income Taxes

As of December 31, 2012, the Company believes that it has no liability for uncertain tax positions. If the Company were to determine there were any uncertain tax positions, the Company would recognize the liability and related interest and penalties within income tax expense. As of December 31, 2012, the Company had no provision for interest or penalties related to uncertain tax positions. The Company files income tax returns in Canada and U.S. federal jurisdiction and various states. There are currently no Canadian or U.S. federal or state income tax examinations underway for these jurisdictions. Furthermore, the Company is no longer subject to U.S. federal income tax examinations by the Internal Revenue Service, state or local tax authorities for tax years ended on or before December 31, 2008 or Canadian tax examinations by the Canadian Revenue Agency for tax years ended on or before December 31, 2001. Although certain tax years are closed under the statute of limitations, tax authorities can still adjust tax losses being carried forward to open tax years.

Note 7—Commodity Derivative Instruments

Through its wholly-owned subsidiary Kodiak Oil & Gas (USA) Inc., the Company has entered into commodity derivative instruments, as described below. The Company has utilized swaps or "no premium" collars to reduce the effect of price changes on a portion of our future oil production. A collar requires us to pay the counterparty if the settlement price is above the ceiling price and requires the counterparty to pay us if the settlement price is below the floor price. A swap requires us to pay the counterparty if the settlement price exceeds the strike price and the same counterparty is required to pay us if the settlement price is less than the strike price. The objective of the Company's use of derivative financial instruments is to achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage its exposure to commodity price risk. While the use of these derivative instruments limits the downside risk of adverse price movements, such use may also limit the Company's ability to benefit from favorable price movements. The Company may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of the Company's existing positions. The Company does not enter into derivative contracts for speculative purposes.

The use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. The Company's derivative contracts are currently with six counterparties. The Company has netting arrangements with the counterparties that provide for the offset of payables against receivables from separate derivative arrangements with the counterparties in the event of contract termination. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement.

The Company's commodity derivative instruments are measured at fair value and are included in the accompanying balance sheets as commodity price risk management assets and liabilities. Unrealized gains and losses are recorded based on the changes in the fair values of the derivative instruments. Both the unrealized and realized gains and losses resulting from the contract settlement of derivatives are recorded in the commodity price risk management activities line on the consolidated statement of income. The Company's valuation estimate takes into consideration the counterparties' credit worthiness, the Company's credit worthiness, and the time value of money. The consideration of the factors results in an estimated exit-price for each derivative asset or liability under a market place participant's view. Management believes that this approach provides a reasonable, non-biased, verifiable, and consistent methodology for valuing commodity derivative instruments.

The Company's commodity derivative contracts as of December 31, 2012 are summarized below:

Contract Type	Counterparty	Basis(1)	Quantity (Bbl/d)	Strike Price ($/Bbl)	Term
Collar	Shell Trading (U.S.)	NYMEX	500	$85.00 - $117.00	Jan 1, 2013—Dec 31, 2013
Collar	Wells Fargo Bank, N.A.	NYMEX	300 - 425	$85.00 - $102.75	Jan 1, 2013—Dec 31, 2015

Contract Type	Counterparty	Basis(1)	Quantity (Bbl/d)	Swap Price ($/Bbl)	Term
Swap	Wells Fargo Bank, N.A.	NYMEX	79	$84.00	Jan 1, 2013—Dec 31, 2013
Swap	Wells Fargo Bank, N.A.	NYMEX	427	$88.30	Jan 1, 2013—Dec 31, 2013
Swap	Wells Fargo Bank, N.A.	NYMEX	24	$90.28	Jan 1, 2013—Dec 31, 2013
Swap	Wells Fargo Bank, N.A.	NYMEX	500	$85.00	Jan 1, 2013—Dec 31, 2013
Swap	Wells Fargo Bank, N.A.	NYMEX	400	$85.07	Jan 1, 2013—Dec 31, 2013
Swap	Wells Fargo Bank, N.A.	NYMEX	425	$93.20	Jan 1, 2013—Dec 31, 2013
Swap	Wells Fargo Bank, N.A.	NYMEX	1,000	$104.13	Jan 1, 2013—Dec 31, 2013
Swap	Wells Fargo Bank, N.A.	NYMEX	1,000	$101.55	Jan 1, 2013—Dec 31, 2013
Swap	Wells Fargo Bank, N.A.	NYMEX	1,000	$95.95	Jan 1, 2013—Dec 31, 2013
Swap	Wells Fargo Bank, N.A.	NYMEX	500	$92.30	Jan 1, 2013—Dec 31, 2013
Swap	Wells Fargo Bank, N.A.	NYMEX	500	$97.70	Jan 1, 2013—Dec 31, 2013
Swap	Shell Trading (U.S.)	NYMEX	250	$85.01	Jan 1, 2013—Dec 31, 2013
Swap	Shell Trading (U.S.)	NYMEX	500	$101.32	Jan 1, 2013—Dec 31, 2013
Swap	Shell Trading (U.S.)	NYMEX	500	$95.98	Jan 1, 2013—Dec 31, 2013
Swap	Shell Trading (U.S.)	NYMEX	500	$92.51	Jan 1, 2013—Dec 31, 2013
Swap	Credit Suisse International	NYMEX	1,000	$101.60	Jan 1, 2013—Dec 31, 2013
Swap	Credit Suisse International	NYMEX	1,000	$95.98	Jan 1, 2013—Dec 31, 2013
Swap	KeyBank	NYMEX	1,000	$92.40	Jan 1, 2013—Dec 31, 2013
Swap	KeyBank	NYMEX	500	$97.70	Jan 1, 2013—Dec 31, 2013
Swap	KeyBank	NYMEX	500	$91.73	Jan 1, 2013—Dec 31, 2013
Swap	Scotiabank	NYMEX	500	$91.53	Jan 1, 2013—Dec 31, 2013
2013 Total/Average			**12,105**	**$95.49**	
Swap	Wells Fargo Bank, N.A.	NYMEX	69	$84.00	Jan 1, 2014—Dec 31, 2014
Swap	Wells Fargo Bank, N.A.	NYMEX	360	$88.30	Jan 1, 2014—Dec 31, 2014
Swap	Wells Fargo Bank, N.A.	NYMEX	21	$90.28	Jan 1, 2014—Dec 31, 2014
Swap	Wells Fargo Bank, N.A.	NYMEX	350	$93.20	Jan 1, 2014—Dec 31, 2014
Swap	Wells Fargo Bank, N.A.	NYMEX	1,000	$85.07	Jan 1, 2014—Dec 31, 2014
Swap	Credit Suisse International	NYMEX	1,000	$100.05	Jan 1, 2014—Dec 31, 2014
2014 Total/Average			**2,800**	**$91.86**	
Swap	Wells Fargo Bank, N.A.	NYMEX	317	$88.30	Jan 1, 2015—Sept 30, 2015
Swap	Wells Fargo Bank, N.A.	NYMEX	59	$84.00	Jan 1, 2015—Oct 31, 2015
Swap	Wells Fargo Bank, N.A.	NYMEX	46	$90.28	Jan 1, 2015—Oct 31, 2015
Swap	Wells Fargo Bank, N.A.	NYMEX	300	$93.20	Jan 1, 2015—Dec 31, 2015
Swap	Wells Fargo Bank, N.A.	NYMEX	1,000	$85.07	Jan 1, 2015—Dec 31, 2015
2015 Total/Average			**1,625**	**$87.13**	

(1) NYMEX refers to quoted prices on the New York Mercantile Exchange

Subsequent to December 31, 2012, the Company entered into additional commodity derivative contracts as summarized below:

Contract Type	Counterparty	Basis(1)	Quantity (Bbl/d)	Swap Price ($/Bbl)	Term
Swap	Wells Fargo	NYMEX	1,000	$94.06	Jan 1, 2013—Dec 31, 2013
Swap	Wells Fargo	NYMEX	500	$96.34	Feb 1, 2013—Dec 31, 2013
Swap	JP Morgan	NYMEX	1,000	$96.47	Feb 1, 2013—Dec 31, 2013
2013 Total/Average			**2,373**	**$95.41**	
Swap	Wells Fargo	NYMEX	500	$92.65	Jan 1, 2014—Dec 31, 2014
Swap	Wells Fargo	NYMEX	500	$92.75	Jan 1, 2014—Dec 31, 2014
Swap	Shell	NYMEX	500	$94.09	Jan 1, 2014—Dec 31, 2014
Swap	Shell	NYMEX	500	$92.76	Jan 1, 2014—Dec 31, 2014
Swap	Key Bank	NYMEX	300	$94.05	Jan 1, 2014—Dec 31, 2014
Swap	Scotiabank	NYMEX	500	$92.65	Jan 1, 2014—Dec 31, 2014
Swap	JP Morgan	NYMEX	1,000	$93.02	Jan 1, 2014—Dec 31, 2014
Swap	JP Morgan	NYMEX	200	$94.03	Jan 1, 2014—Dec 31, 2014
2014 Total/Average			**4,000**	**$93.12**	

The following table details the fair value of the derivatives recorded in the applicable consolidated balance sheet, by category (in thousands):

Underlying Commodity	Location on Balance Sheet	As of December 31, 2012	As of December 31, 2011
Crude oil derivative contract	Current assets	$ 10,864	$ —
Crude oil derivative contract	Noncurrent assets	$ 2,850	$ —
Crude oil derivative contract	Current liabilities	$ 304	$ 11,925
Crude oil derivative contract	Noncurrent liabilities	$ 4,288	$ 10,035

The amount of gain (loss) recognized in the statements of operations related to the Company's derivative financial instruments was as follows (in thousands):

	For the Years Ended December 31,	
	2012	2011
Unrealized gain (loss) on oil contracts	$ 31,082	$ (16,217)
Realized gain (loss) on oil contracts	13,520	(3,897)
Gain (loss) on commodity price risk management activities	$ 44,602	$ (20,114)

Note 8—Asset Retirement Obligations

The Company follows accounting for asset retirement obligations in accordance with ASC 410, *Asset Retirement and Environmental Obligations*, which requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it was incurred if a reasonable estimate of fair value could be made. The Company's asset retirement obligations primarily represent the estimated present value of the amounts expected to be incurred to plug, abandon and remediate producing and shut-in wells at the end of their productive lives in accordance with applicable state and federal laws. The Company determines the estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities. The significant inputs used to calculate such liabilities include estimates of costs to be incurred; the Company's credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement costs are depleted as a component of the full cost pool using the unit of production method.

The following table summarizes the activities of the Company's asset retirement obligation for the years ended December 31, 2012 and 2011 (in thousands):

	For the Years Ended December 31,	
	2012	2011
Balance beginning of period	$ 3,627	$ 1,968
Liabilities incurred or acquired	4,537	1,655
Liabilities settled	(58)	(610)
Revisions in estimated cash flows	405	418
Accretion expense	553	196
Balance end of period	$ 9,064	$ 3,627

Note 9—Fair Value Measurements

ASC Topic 820, *Fair Value Measurement and Disclosure*, establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

- Level 1: Quoted prices are available in active markets for identical assets or liabilities;
- Level 2: Quoted prices in active markets for similar assets and liabilities that are observable for the asset or liability;
- Level 3: Unobservable pricing inputs that are generally less observable from objective sources, such as discounted cash flow models or valuations.

The financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. There were no significant assets or liabilities that were measured at fair value on a non-recurring basis in periods after initial recognition.

The Company's non-recurring fair value measurements include asset retirement obligations, please refer to *Note 8—Asset Retirement Obligations*, and the purchase price allocations for the fair value of assets and liabilities acquired through business combinations, please refer to *Note 4—Acquisitions.*

The Company determines the estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities using level 3 inputs. The significant inputs used to calculate such liabilities include estimates of costs to be incurred; the Company's credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement cost is depleted as a component of the full cost pool using the units-of-production method.

The fair value of assets and liabilities acquired through business combinations is calculated using a discounted-cash flow approach using level 3 inputs. Cash flow estimates require forecasts and assumptions for many years into the future for a variety of factors, including risk-adjusted oil and gas reserves, commodity prices and operating costs.

The following table presents the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2012 and 2011 by level within the fair value hierarchy (in thousands):

	Fair Value Measurements at December 31, 2012 Using			
	Level 1	Level 2	Level 3	Total
Financial Assets and Liabilities:				
Commodity price risk management asset	$ —	$ 13,714	$ —	$ 13,714
Commodity price risk management liability	$ —	$ 4,592	$ —	$ 4,592

	Fair Value Measurements at December 31, 2011 Using			
	Level 1	Level 2	Level 3	Total
Financial Assets and Liabilities:				
Commodity price risk management asset	$ —	$ 21,960	$ —	$ 21,960
Commodity price risk management liability	$ —	$ —	$ —	$ —

The following methods and assumptions were used to estimate the fair value of the assets and liabilities in the table above:

Commodity Derivative Instruments

The Company determines its estimate of the fair value of derivative instruments using a market approach based on several factors, including quoted market prices in active markets, quotes from third parties, the credit rating of each counterparty, and the Company's own credit rating. In consideration of counterparty credit risk, the Company assessed the possibility of whether each counterparty to the derivative would default by failing to make any contractually required payments. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions. At December 31, 2012 and 2011, derivative instruments utilized by the Company consist of both "no premium" collars and swaps. The crude oil derivative markets are highly active. Although the Company's derivative instruments are valued using public indices, the instruments themselves are traded with third-party counterparties and are not openly traded on an exchange. As such, the Company has classified these instruments as Level 2.

Fair Value of Financial Instruments

The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable, commodity derivative instruments (discussed above) and long-term debt. The carrying values of cash and cash equivalents and accounts receivable, accounts payable are representative of their fair values due to their short-term maturities. The carrying amount of the Company's credit facility approximated fair value as it bears interest at variable rates over the term of the loan. The fair value of the second lien credit agreement was based on the amount paid on January 10, 2012 to extinguish the debt. The fair value of the 2019 Notes was derived from available market data. This disclosure (in thousands) does not impact our financial position, results of operations or cash flows.

	At December 31, 2012		At December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Credit facility	$ 295,000	$ 295,000	$ —	$ —
Second lien credit agreement	$ —	$ —	$ 100,000	$ 103,000
2019 Notes	$ 805,622	$ 890,000	$ 650,000	$ 656,000

Note 10—Common Stock

In January 2012, the Company issued 5,055,612 shares of common stock valued at approximately $49.8 million to two separate private, unaffiliated oil and gas companies as part of the consideration for the oil and gas properties acquired in January 2012. Please refer to *Note 4—Acquisitions* for additional discussion.

In November 2011, the Company issued 48,300,000 shares of common stock in a public offering, including the full exercise of the underwriters' over-allotment option of 6,300,000 shares. All shares were sold at a price of $7.75 per share. The net proceeds of the offering, after deducting underwriting discounts, commissions and other offering expenses, were approximately $355.5 million. The net proceeds were used to repay all borrowing under the Company's second lien credit agreement in January 2012 and repay all outstanding borrowing under the credit facility at that time.

In July 2011, the Company issued 27,600,000 shares of common stock in a public offering, which included the full exercise of the underwriters' over-allotment option of 3,600,000 shares. All shares were sold at a price of $6.10 per share. The net proceeds of the offering, after deducting underwriting discounts and commissions and Kodiak's estimated offering expenses, were approximately $159.8 million. The Company used $60.0 million of the net proceeds from the offering to repay debt outstanding under the credit facility.

In June 2011, the Company issued 2,500,000 shares of common stock valued at approximately $14.4 million to a private, unaffiliated oil and gas company as part of the consideration for the oil and gas properties acquired in June 2011. Please refer to *Note 4—Acquisitions* for additional discussion.

In December 2010, the Company issued 28,750,000 shares of common stock in a public offering, including the full exercise of the underwriters' over-allotment option of 3,750,000 shares. All shares were sold at a price of $5.50 per share. The net proceeds of the offering, after deducting underwriting discounts, commissions and other offering expenses, were approximately $150.0 million. Approximately $50.0 million was used for reduction of debt and the remaining net proceeds were used for drilling and completion activities on the Company's leases in the Bakken oil play located in Dunn County, North Dakota and for other general corporate activities.

In August 2010, the Company closed a public offering of 28,750,000 shares of common stock, including the full exercise of the underwriters' over-allotment option of 3,750,000 shares. All shares were sold at a price of $2.75 per share. The net proceeds of the offering, after deducting underwriting discounts, commissions and other offering expenses, were approximately $74.6 million. The net proceeds were used principally for drilling and completion activities on the Company's leases in the Bakken oil play located in Dunn County, North Dakota and for other general corporate activities.

Note 11—Share-Based Payments

The Company has granted various equity-based awards to directors, officers, and employees of the Company under the 2007 Stock Incentive Plan, amended on June 3, 2010 and further amended on June 15, 2011 (as so amended, the "Plan"). The Plan authorizes the Company to issue stock options, stock appreciation rights, restricted stock and restricted stock units, performance awards, other stock grants and other stock-based awards to any employee, consultant, independent contractor, director or officer providing services to the Company or to an affiliate of the Company. The maximum number of shares of common stock available for issuance under the Plan is equal to 14% of the Company's issued and outstanding shares of common stock, as calculated on January 1 of each respective year, subject to adjustment as provided in the Plan. As of January 1, 2012, the maximum number of shares issuable under the Plan, including those previously issued thereunder, was approximately 36.1 million shares.

Stock Options

Total compensation expense related to the stock options of $6.4 million, $3.6 million, and $3.6 million was recognized for the years ended December 31, 2012, 2011 and 2010, respectively. As of December 31, 2012, there was $6.6 million of total unrecognized compensation cost related to stock options, which is expected to be amortized over a weighted average period of 1.9 years.

Compensation expense related to stock options is calculated using the Black Scholes-Merton valuation model. Expected volatilities are based on the historical volatility of Kodiak's common stock over a period consistent with that of the expected terms of the options. The expected terms of the options are estimated based on factors such as vesting periods, contractual expiration dates, historical trends in the Company's common stock price and historical exercise behavior. The risk-free rates for periods within the contractual life of the options are based on the yields of U.S. Treasury instruments with terms comparable to the estimated option terms. The following assumptions were used for the Black-Scholes-Merton model to calculate the share-based compensation expense for the period presented:

	For the Years Ended December 31,		
	2012	2011	2010
Risk free rates	0.78-1.48%	1.06 - 2.57%	0.70 - 3.02%
Dividend yield	—%	—%	—%
Expected volatility	85.23 - 90.25%	90.43 - 94.97%	95.01 - 102.11%
Weighted average expected stock option life	5.85 years	6.01 years	4.55 years

The weighted average fair value at the date of grant for stock options granted is as follows:

	2012	2011	2010
Weighted average fair value per share	$ 6.58	$ 5.10	$ 2.29
Total options granted	1,159,500	1,712,500	2,937,000
Total weighted average fair value of options granted	$ 7,629,510	$ 8,733,750	$ 6,732,504

A summary of the stock options outstanding is as follows:

	Number of Options	Weighted Average Exercise Price
Balance outstanding at January 1, 2010:	5,585,000	$ 2.36
Granted	2,937,000	3.26
Canceled	(343,809)	2.15
Exercised	(1,688,274)	2.13
Balance outstanding at December 31, 2010:	6,489,917	$ 2.73
Granted	1,712,500	6.74
Canceled	(616,525)	3.61
Exercised	(994,734)	2.88
Balance outstanding at December 31, 2011:	6,591,158	$ 3.77
Granted	1,159,500	9.08
Canceled	(620,029)	6.06
Exercised	(1,424,678)	2.85
Balance outstanding at December 31, 2012:	5,705,951	$ 4.83
Options exercisable at December 31, 2012:	3,384,036	$ 3.26

The following table summarizes information about stock options outstanding at December 31, 2012:

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Number of Options Outstanding	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Number of Options Exercisable	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price
$ 0.36-$1.00	241,000	6.0	$ 0.36	241,000	6.0	$ 0.36
$1.01-$2.00	547,448	1.4	$ 1.18	547,448	1.4	$ 1.18
$2.01-$3.00	816,700	6.6	$ 2.36	558,285	6.4	$ 2.34
$3.01-$4.00	1,478,303	3.6	$ 3.47	1,401,303	3.4	$ 3.46
$4.01-$5.00	147,000	8.3	$ 4.47	68,000	8.1	$ 4.39
$5.01-$6.00	242,500	8.5	$ 5.57	86,500	8.4	$ 5.62
$6.01-$7.00	855,500	7.2	$ 6.46	355,500	6.6	$ 6.41
$7.01-$8.00	294,000	9.1	$ 7.50	26,000	8.4	$ 7.16
$8.01-$9.00	470,000	9.2	$ 8.73	72,000	8.9	$ 8.69
$9.01-$10.53	613,500	9.0	$ 9.72	28,000	8.9	$ 9.09
	5,705,951	6.1	$ 4.83	3,384,036	4.5	$ 3.26

The aggregate intrinsic value of both outstanding and vested options as of December 31, 2012 was $23.5 million, based on the Company's December 31, 2012 closing common stock price of $8.85. This amount would have been received by the option holders had all option holders exercised their options as of that date. The total grant date fair value of the shares vested during 2012 was $3.7 million.

Restricted Stock Units and Restricted Stock

Total compensation expense related to restricted stock units ("RSUs") and restricted stock of $4.8 million, $1.6 million, and $867,000 was recognized for the years ended December 31, 2012, 2011, and 2010, respectively. As of December 31, 2012, there was $12.4 million of total unrecognized compensation cost related to the RSUs and restricted stock, which is expected to be amortized over a weighted average period of 2.3 years.

During the first quarter of 2012, the Company awarded 30,000 shares of restricted stock to its Board of Directors pursuant to the Plan. These restricted stock shares vest over a four year period and the Company began recognizing compensation expense related to these grants in the first quarter of 2012. The Company recognizes compensation cost for these grants on a straight-line basis over the requisite service period for the entire award. The fair value of restricted stock is based on the stock price on the grant date and the Company assumes a 3% annual forfeiture rate.

In the fourth quarter 2012, the Company awarded 1,077,873 performance based restricted stock shares to officers pursuant to the Plan. Subject to the satisfaction of certain 2013 performance-based conditions, the restricted stock shares vest one-quarter per year over a four year service period and the Company began recognizing compensation expense related to these grants beginning in the fourth quarter 2012 over the vesting period. The Company recognizes compensation cost for performance based grants on a tranche level basis over the requisite service period for the entire award. Each quarter, the Company evaluates the actual performance results compared to the performance metrics and estimates the probability of the metrics being satisfied. The Company adjusts the number of shares expected to be granted and related expense based on its assessment. The Company is currently assuming that the maximum number of shares will be awarded and expensing accordingly. The fair value of the restricted stock shares granted is based on the stock price on the grant date and the Company assumed a 1.4% annual forfeiture rate.

As of December 31, 2012, there were 729,208 unvested performance based RSUs, 1,077,873 unvested performance based restricted stock shares and 22,500 unvested restricted stock shares with a combined weighted average grant date fair value of $8.93 per share. The total fair value vested during 2012 was $2.4 million. A summary of the RSUs and restricted stock shares outstanding is as follows:

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested restricted stock and RSUs at January 1, 2010	8,000	$ 3.59
Granted	175,000	6.60
Forfeited	—	—
Vested	—	—
Non-vested restricted stock and RSUs at December 31, 2010	183,000	$ 6.47
Granted	1,025,085	8.51
Forfeited	—	—
Vested	(199,974)	6.78
Non-vested restricted stock and RSUs at December 31, 2011	1,008,111	$ 8.48
Granted	1,107,873	9.18
Forfeited	—	—
Vested	(286,403)	8.30
Non-vested restricted stock and RSUs at December 31, 2012	1,829,581	$ 8.93

Note 12—Earnings Per Share

Basic net income (loss) per share is computed by dividing net income (loss) attributable to the common stockholders by the weighted average number of common shares outstanding during the reporting period. Diluted net income per common share includes shares of restricted stock units, and the potential dilution that could occur upon exercise of options to acquire common stock computed using the treasury stock method, which assumes that the increase in the number of shares is reduced by the number of shares which could have been repurchased by the Company with the proceeds from the exercise of the options (which were assumed to have been made at the average market price of the common shares during the reporting period).

In accordance with ASC 260-10-45, *Share-Based Payment Arrangements and Participating Securities and the Two-Class Method*, the Company's unvested restricted stock shares are deemed participating securities, since these shares would be entitled to participate in dividends declared on common shares. During periods of net income, the calculation of earnings per share for common stock exclude income attributable to the restricted stock shares from the numerator and exclude the dilutive impact of those shares from the denominator. During periods of net loss, no effect is given to the participating securities because they do not share in the losses of the Company.

The performance based restricted stock units and unexercised stock options are not participating securities, since these shares are not entitled to participate in dividends declared on common shares. The number of potentially dilutive shares attributable to the performance based restricted stock units is based on the number of shares, if any, which would be issuable at the end of the respective reporting period, assuming that date was the end of the performance measurement period. Please refer to *Note 11—Share-Based Payments* under the heading Restricted Stock Units and Restricted Stock for additional discussion.

The table below sets forth the computations of basic and diluted net income (loss) per share for the years ended December 31, 2012, 2011, and 2010 (in thousands, except per share data):

	For the Years Ended December 31,		
	2012	2011	2010
Basic net income (loss)	$ 131,584	$ 3,875	$ (2,402)
Income allocable to participating securities	(15)	(1)	—
Diluted net income (loss)	$ 131,569	$ 3,874	$ (2,402)
Basic weighted average common shares outstanding	263,531,408	197,579,298	131,444,440
Effect of dilutive securities			
Options to purchase common shares	5,092,451	5,567,158	—
Assumed treasury shares purchased	(1,696,667)	(2,691,509)	—
Unvested restricted stock units	744,104	97,045	—
Diluted weighted average common shares outstanding	267,671,296	200,551,992	131,444,440
Basic net income (loss) per share	$ 0.50	$ 0.02	$ (0.02)
Diluted net income (loss) per share	$ 0.49	$ 0.02	$ (0.02)

The following options and unvested restricted shares, which could be potentially dilutive in future periods, were not included in the computation of diluted net income per share because the effect would have been anti-dilutive for the periods indicated:

	For the Years Ended December 31,		
	2012	2011	2010
Anti-dilutive shares	613,500	1,121,045	1,207,000

Note 13—Benefit Plans

401(k) Plan

In 2008 the Company established a 401(k) plan for the benefit of its employees. Eligible employees may make voluntary contributions not exceeding statutory limitations to the plan. The Company matches 100% of employee contributions up to 3% of the employee's salary and 50% of an additional 2% of employee contributions. The Company's matching contributions are 100% vested upon participation. The matching contribution recorded in 2012 and 2011 respectively was $346,000 and $214,000.

Other Company Benefits

The Company provides a health, dental, vision, life, and disability insurance benefit to all regular full-time employees paid to a maximum of $1,000 per month per employee.

Note 14—Commitments and Contingencies

Leases

The Company leases office space in Denver, Colorado and Williston and Dickinson, North Dakota under separate operating lease agreements. The Denver, Colorado lease expires on October 31, 2016. The Williston and Dickinson, North Dakota leases expire on May 31, 2013 and December 31, 2014 respectively. Total rental commitments under non-cancelable leases for office space were $3.4 million at December 31, 2012. The future minimum lease payments under these non-cancelable leases are as follows: $880,000 in 2013, $910,000 in 2014, $860,000 in 2015, $770,000 in 2016, and $0 in 2017.

Drilling Rigs

As of December 31, 2012 the Company was subject to commitments on six drilling rig contracts. Five of the contracts expire in 2013 and one expires in 2015. In the event of early termination under all of these contracts, the Company would be obligated to pay an aggregate amount of approximately $32.0 million as of December 31, 2012 as required under the varying terms of such contracts.

Pressure Pumping Services

As of December 31, 2012, the Company was subject to a commitment with a pressure-pumping service company providing 24-hour per day crew availability. In the event of early contract termination, the Company would be obligated to pay approximately $24.0 million as of December 31, 2012.

Guarantees

As of December 31, 2012, the Company had issued $800.0 million of 2019 Notes and in January 2013 issued $350.0 million of 2021 Notes, all of which are guaranteed on a senior unsecured basis by our wholly owned subsidiary, Kodiak Oil & Gas (USA) Inc. Kodiak Oil & Gas Corp, as the parent company, has no independent assets or operations. The guarantee is full and unconditional, and the parent company has no other subsidiaries. In addition, there are no restrictions on the ability of the parent company to obtain funds from its subsidiary by dividend or loan (other than as described in *Note 5 - Long Term Debt)*. Finally, the parent Company's wholly- owned subsidiary does not have restricted assets that exceed 25% of net assets as of the most recent fiscal year end that may not be transferred to the parent company in the form of loans, advances, or cash dividends by the subsidiary without the consent of a third party.

The Company may issue additional debt securities in the future that the Company's wholly-owned subsidiary, Kodiak Oil & Gas (USA) Inc., may guarantee. Any such guarantee is expected to be full, unconditional and joint and several. As stated above, the Company has no independent assets or operations nor does it have any other subsidiaries, and there are no significant restrictions on the ability of the Company to receive funds from the Company's subsidiary through dividends, loans, and advances or otherwise.

Other

As is customary in the oil and gas industry, the Company may at times have commitments in place to reserve or earn certain acreage positions or wells. If the Company does not meet such commitments, the acreage positions or wells may be lost.

Note 15—Supplemental Oil and Gas Reserve Information (Unaudited)

Oil and Natural Gas Reserve Quantities (Unaudited)

The reserves at December 31, 2012, 2011 and 2010 presented below were prepared by the independent engineering firm, Netherland, Sewell & Associates, Inc. All reserves are located within the continental United States. Proved oil and natural gas reserves are the estimated quantities of oil and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions (i.e., prices and costs) existing at the time the estimate is made. Proved developed oil and natural gas reserves are proved reserves that can be expected to be recovered through existing wells and equipment in place and under operating methods being utilized at the time the estimates were made. A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are decline curve analysis, advance production type curve matching, petro-physics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

The following table sets forth information for the years ended December 31, 2012, 2011 and 2010 with respect to changes in the Company's proved (i.e. proved developed and undeveloped) reserves:

	Crude Oil (MBbls)	Natural Gas (MMcf)
December 31, 2009	3,816.7	3,848.4
Revisions of previous estimates	329.7	(202.7)
Purchase of reserves	3,059.5	2,905.9
Extensions, discoveries, and other additions	3,236.8	2,570.6
Sale of reserves	—	—
Production	(432.3)	(162.1)
December 31, 2010	10,010.4	8,960.1
Revisions of previous estimates	1,983.2	268.5
Purchase of reserves	7,104.8	4,995.4
Extensions, discoveries, and other additions	17,821.8	12,108.6
Sale of reserves	(0.2)	(270.7)
Production	(1,344.5)	(522.7)
December 31, 2011	35,575.5	25,539.2
Revisions of previous estimates	1,965.2	17,954.8
Purchase of reserves	10,510.6	8,283.8
Extensions, discoveries, and other additions	37,582.6	34,647.8
Sale of reserves	—	—
Production	(4,704.1)	(3,302.0)
December 31, 2012	80,929.8	83,123.6
Proved Developed Reserves, included above:		
Balance, December 31, 2009	1,170.4	1,454.9
Balance, December 31, 2010	3,756.4	3,653.0
Balance, December 31, 2011	13,178.8	8,956.8
Balance, December 31, 2012	36,158.0	41,870.3
Proved Undeveloped Reserves, included above:		
Balance, December 31, 2009	2,646.3	2,393.5
Balance, December 31, 2010	6,254.0	5,307.1
Balance, December 31, 2011	22,396.7	16,582.4
Balance, December 31, 2012	44,771.8	41,253.3

- The values for the 2012 oil and gas reserves are based on the 12 month arithmetic average first of month price January through December 31, 2012 crude oil price of $94.68 per barrel (West Texas Intermediate price) and natural gas price of $2.58 per MMBtu (Questar Rocky Mountains price) or $2.77 per MMBtu (Northern Ventura price). All prices are then further adjusted for transportation, quality and basis differentials. The average resulting price used as of December 31, 2012 was $82.84 per barrel of oil and $5.73 per Mcf for natural gas.

- The values for the 2011 oil and gas reserves are based on the 12 month arithmetic average first of month price January through December 31, 2011 crude oil price of $95.99 per barrel (West Texas Intermediate price) and natural gas price of $3.94 per MMBtu (Questar Rocky Mountains price) or $4.17 per MMBtu (Northern Ventura price). All prices are then further adjusted for transportation, quality and basis differentials. The average resulting price used as of December 31, 2011 was $88.40 per barrel of oil and $5.50 per Mcf for natural gas.

- The values for the 2010 oil and gas reserves are based on the 12 month arithmetic average first of month price January through December 31, 2010 crude oil price of $79.40 per barrel (West Texas Intermediate price) and natural gas price of $3.92 per MMBtu (Questar Rocky Mountains price) or $4.39 per MMBtu (Northern Ventura price). All prices are then further adjusted for transportation, quality and basis differentials. The average resulting price used as of December 31, 2010 was $69.15 per barrel of oil and $5.07 per Mcf for natural gas.

For the year ended December 31, 2012, the Company had upward revisions of previous estimates of 1,965.2 MBbls and 17,954.8 MMcf. These revisions are primarily the result of improved well performance. As a result of ongoing drilling and completion activities during 2012, the Company reported extensions, discoveries, and other additions of 37,582.6 MBbls and 34,647.8 MMcf. Additionally, in 2012, the Company had purchases of reserves of 10,510.6 MMbls and 8,283.8 MMcf as a result of the January 2012 Acquisition.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

The Company follows the guidelines prescribed in ASC Topic 932, *Extractive Activities—Oil and Gas* for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The following summarizes the policies used in the preparation of the accompanying oil and natural gas reserve disclosures, standardized measures of discounted future net cash flows from proved oil and natural gas reserves and the reconciliations of standardized measures from year to year.

The information is based on estimates of proved reserves attributable to the Company's interest in oil and natural gas properties as of December 31 of the years presented. These estimates were prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows: (1) Estimates are made of quantities of proved reserves and future periods during which they are expected to be produced based on year-end economic conditions. (2) The estimated future cash flows are compiled by applying the twelve month average of the first of the month prices of crude oil and natural gas relating to the Company's proved reserves to the year-end quantities of those reserves for reserves. (3) The future cash flows are reduced by estimated production costs, costs to develop and produce the proved reserves and abandonment costs, all based on year-end economic conditions, plus Company overhead incurred. (4) Future income tax expenses are based on year-end statutory tax rates giving effect to the remaining tax basis in the oil and natural gas properties, other deductions, credits and allowances relating to the Company's proved oil and natural gas reserves. (5) Future net cash flows are discounted to present value by applying a discount rate of 10%.

The assumptions used to compute the standardized measure are those prescribed by the FASB and the SEC. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations, since these reserve quantity estimates are the basis for the valuation process. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of the Company's oil and natural gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The following summary sets forth the Company's future net cash flows relating to proved oil and gas reserves based on the standardized measure prescribed in ASC Topic 932 (in thousands):

	For the Years Ended December 31,		
	2012	**2011**	**2010**
Future oil and gas sales	$ 7,179,856	$ 3,285,461	$ 737,631
Future production costs	(2,078,147)	(962,680)	(185,405)
Future development costs	(1,072,131)	(504,762)	(145,093)
Future income tax expense	(694,877)	(431,650)	(31,980)
Future net cash flows	3,334,701	1,386,369	375,153
10% annual discount	(1,726,174)	(726,394)	(220,585)
Standardized measure of discounted future net cash flows (1)	$ 1,608,527	$ 659,975	$ 154,568

(1) Our calculations of the standardized measure of discounted future net cash flows include the effect of estimated future income tax expenses for all years reported. For purposes of the Standardized Measure calculation, it was assumed that all of our NOLs will be realized within future carryforward periods. All of the Company's operations, and resulting NOLs, are attributable to our oil and gas assets.

The following are the principal sources of change in the Standardized Measure (in thousands):

	For the Years Ended December 31, 2012	2011	2010
Balance at beginning of period	$ 659,975	$ 154,568	$ 39,063
Sales of oil and gas, net	(323,192)	(93,102)	(24,200)
Net change in prices and production costs	(23,839)	92,165	30,398
Net change in future development costs	(14,706)	(8,563)	(1,739)
Extensions and discoveries	710,912	424,635	39,120
Acquisition of reserves	267,932	165,152	42,007
Sale of reserves	—	(29)	—
Revisions of previous quantity estimates	100,376	43,311	4,144
Previously estimated development costs incurred	265,174	34,236	14,904
Net change in income taxes	(119,847)	(184,146)	(6,560)
Accretion of discount	111,127	16,113	3,906
Other	(25,385)	15,635	13,525
Balance at end of period	$ 1,608,527	$ 659,975	$ 154,568

Note 16—Quarterly Financial Information (Unaudited):

The Company's quarterly financial information for the years ended December 31, 2012 and 2011 is as follows (in thousands, except share data):

	For the Year Ended December 31, 2012			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenue	$ 79,936	$ 85,768	$ 112,140	$ 130,846
Income from operations (1)	$ 36,341	$ 34,379	$ 45,470	$ 51,368
Other income (expense)	$ (26,699)	$ 92,755	$ (36,848)	$ (3,854)
Net income (loss)	$ 1,744	$ 93,072	$ 3,476	$ 33,292
Basic net income (loss) per share	$ 0.01	$ 0.35	$ 0.01	$ 0.13
Diluted net income (loss) per share	$ 0.01	$ 0.35	$ 0.01	$ 0.12
Net cash provided by operating activities (2)	$ 69,051	$ 44,974	$ 89,230	$ 69,424
Net cash used in investing activities (2)	$ (697,173)	$ (208,170)	$ (215,424)	$ (227,311)
Net cash provided by financing activities	$ 571,423	$ 151,787	$ 114,448	$ 180,197

	For the Year Ended December 31, 2011			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenue	$ 13,334	$ 22,113	$ 29,528	$ 55,011
Income from operations (1)	$ 7,039	$ 13,148	$ 16,222	$ 24,624
Other income (expense)	$ (9,556)	$ 5,061	$ 19,172	$ (52,340)
Net income (loss)	$ (7,235)	$ 14,020	$ 30,845	$ (33,755)
Basic net income (loss) per share	$ (0.04)	$ 0.08	$ 0.15	$ (0.15)
Diluted net income (loss) per share	$ (0.04)	$ 0.08	$ 0.15	$ (0.15)
Net cash provided by operating activities	$ 7,152	$ 16,353	$ 19,632	$ 10,776
Net cash used in investing activities	$ (33,125)	$ (116,761)	$ (89,694)	$ (351,169)
Net cash provided by financing activities	$ 930	$ 74,698	$ 98,258	$ 343,356

(1) Excludes interest income (expense), other income (expense), unrealized gain (loss) on commodity price risk management activities, general and administrative expense and income tax expense (benefit).

(2) A reclassification was made for the first, second, and third quarters of 2012 to reclassify capitalized interest from operating activities to investing activities in the amounts of $12.5 million, $12.0 million and $11.2 million, respectively. For the quarterly periods ended March 31, 2012, June 30, 2012 and September 30, 2012 filed on Form 10-Q capitalized interest was included in operating activities. The reclassifications increased operating activities and decreased investing activities by the aforementioned amounts for each respective quarter.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Management of the Company, including the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), have evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this Form 10-K. The term "disclosure controls and procedures" means controls and other procedures established by the Company that are designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the Company's management, including its CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure.

Based upon their evaluation of the Company's disclosure controls and procedures, the CEO and the CFO concluded that the disclosure controls are effective to provide reasonable assurance that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is accumulated and communicated to management, including the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure and are effective to provide reasonable assurance that such information is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms.

The Company, including its CEO and CFO, does not expect that its internal controls and procedures will prevent or detect all error and all fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Management's Annual Report on Internal Control Over Financial Reporting

In accordance with Item 308 of SEC Regulation S-K, management is required to provide an annual report regarding internal controls over our financial reporting. This report, which includes management's assessment of the effectiveness of our internal controls over financial reporting, is found below.

Management's Report on Internal Control over Financial Reporting

Management of the Company 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 Exchange Act. Internal control over financial reporting is a process designed by, or under the supervision of, the CEO and CFO 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. Internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records which in reasonable detail accurately and fairly reflect the transactions and dispositions of the Company's assets; (ii) 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 in accordance with authorizations of management and directors of the issuer; and (iii) 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 controls 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 policies or procedures may deteriorate.

Management (with the participation of the principal executive officer and principal financial officer) conducted an evaluation of the effectiveness of the Company's internal control over financial reporting as of December 31, 2012 based on the framework set forth in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management, with the participation of the CEO and CFO, concluded that the Company's internal control over financial reporting was effective as of December 31, 2012. Ernst & Young LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this report, has issued an attestation report on the effectiveness of internal control over financial reporting.

Attestation Report of Registered Public Accounting Firm

The attestation report required under this Item 9A is set forth below under the caption "Report of Independent Registered Public Accounting Firm."

Changes in Internal Control over Financial Reporting

Management, with the participation of the CEO and CFO, concluded that there were no changes in the Company's internal control over financial reporting during the quarter ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of Kodiak Oil & Gas Corp.

We have audited Kodiak Oil & Gas Corp.'s (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 (the COSO criteria). Kodiak Oil & Gas Corp.'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, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with 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, Kodiak Oil & Gas Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Kodiak Oil & Gas Corp. as of December 31, 2012 and 2011 and the related consolidated statements of operations, stockholder's equity, and cash flows for the years then ended, and our report dated February 28, 2013 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Denver, Colorado
February 28, 2013

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information responsive to Items 401, 405, 406 and 407 of Regulation S-K to be included in our definitive Proxy Statement for our 2013 Annual Meeting of Shareholders, to be filed within 120 days of December 31, 2012, pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended (the "2013 Proxy Statement"), is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information responsive to Items 402 and 407 of Regulation S-K to be included in our 2013 Proxy Statement is incorporated herein by reference.

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

The information responsive to Items 201(d) and 403 of Regulation S-K to be included in our 2013 Proxy Statement is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information responsive to Items 404 and 407 of Regulation S-K to be included in our 2013 Proxy Statement is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information responsive to Item 9(e) of Schedule 14A to be included in our 2013 Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents Filed With This Report

1. FINANCIAL STATEMENTS

The following consolidated financial statements of the Company are filed as a part of this report:

2. FINANCIAL STATEMENT SCHEDULES

None.

3. EXHIBITS

The exhibits listed in (b) below are filed as part of this Annual Report on Form 10-K and incorporated herein by reference.

(b) Exhibits

Exhibit Number	Description
2.1	Asset Purchase Agreement, entered into October 19, 2010, by and among Peak Grasslands, LLC, Kodiak Oil & Gas (USA) Inc., and Kodiak Oil & Gas Corp. (filed as Exhibit 2.1 to the registrant's Current Report on Form 8-K filed on October 25, 2010 and incorporated herein by reference)
2.2	Purchase and Sale Agreement among Ursa Resources Group LLC, Kodiak Oil & Gas (USA) Inc. and Kodiak Oil & Gas Corp. dated May 20, 2011 (filed as Exhibit 2.1 to the registrant's Current Report on Form 8-K/A filed on June 29, 2011 and incorporated herein by reference)
2.3	Purchase and Sale Agreement between BTA Oil Producers LLC, and Kodiak Oil & Gas (USA) Inc. dated September 27, 2011 (filed as Exhibit 2.1 to the registrant's Quarterly Report on Form 10-Q filed on November 3, 2011 and incorporated herein by reference)
2.4	Purchase and Sale Agreement by and among North Plains Energy, LLC (Seller), Kodiak Oil & Gas (USA) Inc. (Buyer) and Kodiak Oil & Gas Corp. (Parent), dated as of November 14, 2011 (filed as Exhibit 2.1 to the registrant's Current Report on Form 8-K/A filed on November 17, 2011 and incorporated herein by reference)
2.5	Purchase and Sale Agreement by and among Mercuria Bakken, LLC (Seller), Kodiak Oil & Gas (USA) Inc. (Buyer) and Kodiak Oil & Gas Corp. (Parent), dated as of November 14, 2011 (filed as Exhibit 2.2 to the registrant's Current Report on Form 8-K/A filed on November 17, 2011 and incorporated herein by reference)
3.1	Certificate of Continuance of Kodiak Oil & Gas Corp., dated September 20, 2001 (filed as Exhibit 1.1 to the registrant's Registration Statement on Form 20-F filed on November 23, 2005 and incorporated herein by reference)
3.2	Articles of Continuation of Kodiak Oil & Gas Corp. (filed as Exhibit 1.2 to the registrant's Registration Statement on Form 20-F filed on November 23, 2005 and incorporated herein by reference)
3.3	Amended and Restated By-Law No. 1 of the Company (filed as Exhibit 3.3 to the registrant's Quarterly Report on Form 10-Q filed on May 9, 2008 and incorporated herein by reference)
3.4	Articles of Incorporation of Kodiak Oil and Gas (USA) Inc. (filed as Exhibit 3.3 to the registrant's Registration Statement on Form S-3 (Registration No. 333-169517) filed on September 22, 2010 and incorporated herein by reference)
4.1	Form of common stock certificate (filed as Exhibit 4.6 to the registrant's Registration Statement on Form S-3ASR (Registration No. 333-173520) filed on April 15, 2011 and incorporated herein by reference)
4.2	Form of senior indenture between Kodiak Oil & Gas Corp. and one or more trustees to be named (filed as Exhibit 4.7 to the registrant's Registration Statement on Form S-3ASR (Registration No. 333-173520) filed on April 15, 2011 and incorporated herein by reference)
4.3	Form of subordinated indenture between Kodiak Oil & Gas Corp. and one or more trustees to be named (filed as Exhibit 4.8 to the registrant's Registration Statement on Form S-3ASR (Registration No. 333-173520) filed on April 15, 2011 and incorporated herein by reference)
4.4	Indenture, dated November 23, 2011, among Kodiak Oil & Gas Corp., Kodiak Oil & Gas (USA) Inc., U.S. Bank National Association and Computershare Trust Company of Canada (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on November 23, 2011 and incorporated herein by reference)
4.5	Indenture, dated January 15, 2013, among Kodiak Oil & Gas Corp., Kodiak Oil & Gas (USA) Inc., U.S. Bank, National Association, as trustee, and Computershare Trust Company of Canada, as the Canadian trustee (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on January 15, 2013 and incorporated herein by reference)
4.6	Registration Rights Agreement, dated November 23, 2011, among Kodiak Oil & Gas Corp., Kodiak Oil & Gas (USA) Inc., Credit Suisse Securities (USA) LLC, Wells Fargo Securities, LLC, KeyBanc Capital Markets Inc. and RBC Capital Markets, LLC (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on November 23, 2011 and incorporated herein by reference)
4.7	Registration Rights Agreement, dated May 17, 2012, among Kodiak Oil & Gas Corp., Kodiak Oil & Gas (USA) Inc., RBC Capital Markets, LLC, Wells Fargo Securities, LLC, and Credit Suisse Securities (USA) LLC (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on May 17, 2012 and incorporated herein by reference)
4.8	Registration Rights Agreement, dated January 15, 2013, among Kodiak Oil & Gas Corp., Kodiak Oil & Gas (USA) Inc., Wells Fargo Securities, LLC, RBC Capital Markets, LLC and Credit Suisse Securities (USA) LLC (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on January 15, 2013 and incorporated herein by reference)
4.9	Officers' Certificate of the Company dated as of May 17, 2012 (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on May 17, 2012 and incorporated herein by reference)

Exhibit Number	Description
10.1	Kodiak Oil & Gas Corp. Incentive Share Option Plan (filed as Exhibit 4.5 to the registrant's Registration Statement on Form 20-F filed on November 23, 2005 and incorporated herein by reference)
10.2	Kodiak Oil & Gas Corp. 2007 Stock Incentive Plan (filed as Appendix A to the registrant's Definitive Proxy Statement filed on April 27, 2007 and incorporated herein by reference)
10.3	Amendment No. 1 to Kodiak Oil & Gas Corp. 2007 Stock Incentive Plan (filed as Appendix A to the registrant's Definitive Proxy Statement filed on April 30, 2010 and incorporated herein by reference)
10.4	Amendment No. 2 to Kodiak Oil & Gas Corp. 2007 Stock Incentive Plan (filed as Appendix A to the registrant's Definitive Proxy Statement filed on April 28, 2011 and incorporated herein by reference)
10.5	Form of Incentive Stock Option Agreement for 2007 Stock Incentive Plan (filed as Exhibit 4.2 to the registrant's Registration Statement on Form S-8 (Registration No. 333-138704) filed on July 26, 2007 and incorporated herein by reference)
10.6	Form of Employee Non-incentive Stock Option Agreement for 2007 Stock Incentive Plan (filed as Exhibit 4.3 to the registrant's Registration Statement on Form S-8 (Registration No. 333-138704) filed on July 26, 2007 and incorporated herein by reference)
10.7	Form of Directors' Non-incentive Stock Option Agreement for 2007 Stock Incentive Plan (filed as Exhibit 4.4 to the registrant's Registration Statement on Form S-8 (Registration No. 333-138704) filed on July 26, 2007 and incorporated herein by reference)
10.8	Form of Non-Incentive Performance-Based Stock Option Agreement for 2007 Stock Incentive Plan (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on March 19, 2008 and incorporated herein by reference)
10.9	Form of Stock Award Agreement for 2007 Stock Incentive Plan (filed as Exhibit 10.8 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2010 filed on March 3, 2011 and incorporated herein by reference)
10.10	Form of Restricted Stock Unit and Performance Award Agreement for 2007 Stock Incentive Plan (filed as Exhibit 10.9 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2010 filed on March 3, 2011 and incorporated herein by reference)
10.11	Form of Restricted Stock and Cash Award Agreement for 2007 Stock Incentive Plan (filed as Exhibit 10.10 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2010 filed on March 3, 2011 and incorporated herein by reference)
10.12	Form of Restricted Stock Unit Award Agreement for 2007 Stock Incentive Plan (filed as Exhibit 10.12 to the registrant's Annual Report on Form 10-K filed on February 28, 2012 and incorporated herein by reference)
10.13	Form of Restricted Stock Agreement for 2007 Stock Incentive Plan (filed as Exhibit 10.13 to the registrant's Annual Report on Form 10-K filed on February 28, 2012 and incorporated herein by reference)
10.14	Form of Stock Option Termination Agreement (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on January 6, 2010 and incorporated herein by reference)
10.15	Fourth Amendment to Lease, dated February 14, 2007, between Transwestern Broadreach WTC, LLC and Kodiak Oil & Gas (USA) Inc. (filed as Exhibit 10.14 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2006 filed on March 27, 2007 and incorporated herein by reference)
10.16	Fifth Amendment to Lease, dated May 31, 2007 between Transwestern Broadreach WTC, LLC and Kodiak Oil & Gas (USA) Inc. (filed as Exhibit 10.3 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2007 filed on March 14, 2008 and incorporated herein by reference)
10.17	Executive Employment Agreement, effective January 1, 2011, by and among Lynn A. Peterson, Kodiak Oil & Gas (USA) Inc. and Kodiak Oil & Gas Corp. (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on January 6, 2011 and incorporated herein by reference)
10.18	Amendment No. 1 to Employment Agreement of Lynn A. Peterson effective January 1, 2013 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on January 28, 2013 and incorporated herein by reference)
10.19	Executive Employment Agreement, effective January 1, 2011, by and among James E. Catlin, Kodiak Oil & Gas (USA) Inc. and Kodiak Oil & Gas Corp. (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on January 6, 2011 and incorporated herein by reference)
10.20	Amendment No. 1 to Employment Agreement of James E. Catlin effective January 1, 2013 (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on January 28, 2013 and incorporated herein by reference)
10.21	Executive Employment Agreement, effective January 1, 2011, by and among James P. Henderson, Kodiak Oil & Gas (USA) Inc. and Kodiak Oil & Gas Corp. (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on January 6, 2011 and incorporated herein by reference)

Exhibit Number	Description
10.22	Amendment No. 1 to Employment Agreement of James P. Henderson effective January 1, 2013 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on January 28, 2013 and incorporated herein by reference)
10.23	Employment Agreement between Kodiak Oil and Gas Corp. and Russell A. Branting dated January 1, 2011 (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q filed on August 4, 2011 and incorporated herein by reference)
10.24	Amendment No. 1 to Employment Agreement of Russell A. Branting (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on June 22, 2012 and incorporated herein by reference)
10.25	Amendment No. 2 to Employment Agreement of Russell A. Branting effective January 1, 2013 (filed as Exhibit 10.4 to the registrant's Current Report on Form 8-K filed on January 28, 2013 and incorporated herein by reference)
10.26	Employment Agreement between Kodiak Oil and Gas Corp. and Russ D. Cunningham dated January 1, 2011 (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q filed on August 4, 2011 and incorporated herein by reference)
10.27	Amendment No. 1 to Employment Agreement of Russ D. Cunningham (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on June 22, 2012 and incorporated herein by reference)
10.28	Amendment No. 2 to Employment Agreement of Russ D. Cunningham effective January 1, 2013 (filed as Exhibit 10.5 to the registrant's Current Report on Form 8-K filed on January 28, 2013 and incorporated herein by reference))
10.29	Credit Agreement dated as of May 24, 2010 among Kodiak Oil & Gas (USA) Inc., Wells Fargo Bank, N.A. and The Lenders Signatory Thereto (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 27, 2010 and incorporated herein by reference)
10.30	First Amendment to Credit Agreement among Kodiak Oil & Gas (USA) Inc., Wells Fargo Bank, N.A. and The Lenders Signatory Thereto, effective as of November 30, 2010 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on December 2, 2010 and incorporated herein by reference)
10.31	Second Amendment to Credit Agreement among Kodiak Oil & Gas (USA) Inc., Wells Fargo Bank, N.A., and the Lenders Signatory Thereto, effective as of April 13, 2011 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on April 19, 2011 and incorporated herein by reference)
10.32	Amended and Restated Credit Agreement, dated as of October 28, 2011, among Kodiak Oil & Gas (USA) Inc., Wells Fargo Bank, N.A. and The Lenders Party Thereto (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on November 3, 2011 and incorporated herein by reference)
10.33	First Amendment and Limited Waiver to Amended and Restated Credit Agreement among Kodiak Oil & Gas (USA) Inc., as Borrower, Wells Fargo Bank, N.A., as Administrative Agent, and The Lenders Signatory Thereto, dated as of November 14, 2011 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on November 14, 2011 and incorporated herein by reference)
10.34	Second Amendment to Amended and Restated Credit Agreement among Kodiak Oil & Gas (USA) Inc., as Borrower, Wells Fargo Bank, N.A., as Administrative Agent, and The Lenders Signatory Thereto, executed as of November 14, 2011 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on November 14, 2011 and incorporated herein by reference)
10.35	Third Amendment to Amended and Restated Credit Agreement among Kodiak Oil & Gas (USA) Inc., as Borrower, Wells Fargo Bank, N.A., as Administrative Agent, and The Lenders Signatory Thereto, dated as of January 10, 2012 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on January 17, 2012 and incorporated herein by reference)
10.36	Fifth Amendment to Amended and Restated Credit Agreement among Kodiak Oil & Gas (USA) Inc., as Borrower, Wells Fargo Bank, N.A., as Administrative Agent, and The Lenders Signatory Thereto, dated as of May 11, 2012 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on May 17, 2012 and incorporated herein by reference)
10.37	Sixth Amendment to Amended and Restated Credit Agreement among Kodiak Oil & Gas (USA) Inc.; as Borrower, Wells Fargo Bank, N.A., as Administrative Agent, and The Lenders Signatory Thereto, dated as of October 15, 2012 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q filed on November 1, 2012 and incorporated herein by reference)
10.38	Seventh Amendment to Amended and Restated Credit Agreement, dated as of January 15, 2013, among Kodiak Oil & Gas (USA) Inc., as Borrower, Wells Fargo Bank, N.A., as Administrative Agent, and the Lenders signatory thereto (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on January 15, 2013 and incorporated herein by reference)

Exhibit Number	Description
10.39	Guarantee and Collateral Agreement dated as of May 24, 2010 by Kodiak Oil & Gas (USA) Inc. in favor of Wells Fargo Bank, N.A. as administrative agent (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on May 27, 2010 and incorporated herein by reference)
10.40	Amended and Restated Guarantee and Collateral Agreement made by each of the Grantors (as defined therein) in favor of Wells Fargo Bank, N.A., dated as of October 28, 2011 (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on November 3, 2011 and incorporated herein by reference)
10.41	Guarantee and Pledge Agreement dated as of May 24, 2010 by Kodiak Oil & Gas Corp. in favor of Wells Fargo Bank, N.A. as administrative agent (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on May 27, 2010 and incorporated herein by reference)
10.42	Amended and Restated Guarantee and Pledge Agreement made by Kodiak Oil & Gas Corp. in favor of Wells Fargo Bank, N.A., dated as of October 28, 2011 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on November 3, 2011 and incorporated herein by reference)
10.43	Second Lien Credit Agreement, dated as of November 30, 2010, among Kodiak Oil & Gas (USA) Inc., Wells Fargo Energy Capital, Inc. and The Lenders Party Thereto (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on December 2, 2010 and incorporated herein by reference)
10.44	Agreement and Amendment No. 1 to Second Lien Credit Agreement, dated as of July 15, 2011, among Kodiak Oil & Gas (USA) Inc., Kodiak Oil & Gas Corp., as guarantor, the lender parties and Wells Fargo Energy Capital, Inc. (filed as exhibit 10.1 to the registrant's Current Report on Form 8-K filed on July 18, 2011 and incorporated herein by reference)
10.45	Amended and Restated Second Lien Credit Agreement, dated as of October 28, 2011, among Kodiak Oil & Gas (USA) Inc., Wells Fargo Energy Capital, Inc. and The Lenders Party Thereto (filed as Exhibit 10.4 to the registrant's Current Report on Form 8-K filed on November 3, 2011 and incorporated herein by reference)
10.46	First Amendment and Limited Waiver to Amended and Restated Second Lien Credit Agreement among Kodiak Oil & Gas (USA) Inc., as Borrower, Wells Fargo Energy Capital, Inc., as Administrative Agent, and The Lenders Signatory Thereto, dated as of November 14, 2011 (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on November 14, 2011 and incorporated herein by reference)
10.47	Second Lien Guarantee and Pledge Agreement made by Kodiak Oil & Gas Corp. in favor of Wells Fargo Energy Capital, Inc., dated as of November 30, 2010 (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on December 2, 2010 and incorporated herein by reference)
10.48	Amended and Restated Second Lien Guarantee and Pledge Agreement made by Kodiak Oil & Gas Corp. in favor of Wells Fargo Energy Capital, Inc., dated as of October 28, 2011 (filed as Exhibit 10.5 to the registrant's Current Report on Form 8-K filed on November 3, 2011 and incorporated herein by reference)
10.49	Second Lien Guarantee and Collateral Agreement made by each of the Grantors (as defined therein) in favor of Wells Fargo Energy Capital, Inc., dated as of November 30, 2010 (filed as Exhibit 10.4 to the registrant's Current Report on Form 8-K filed on December 2, 2010 and incorporated herein by reference)
10.50	Amended and Restated Second Lien Guarantee and Collateral Agreement made by each of the Grantors (as defined therein) in favor of Wells Fargo Energy Capital, Inc., dated as of October 28, 2011. (filed as Exhibit 10.6 to the registrant's Current Report on Form 8-K filed on November 3, 2011 and incorporated herein by reference)
10.51	Purchase Agreement, dated November 18, 2011, among Kodiak Oil & Gas Corp., Kodiak Oil & Gas (USA) Inc., and Credit Suisse Securities (USA) LLC, Wells Fargo Securities, LLC, KeyBanc Capital Markets Inc. and RBC Capital Markets, LLC, as representatives of the several purchasers identified therein (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on November 23, 2011 and incorporated herein by reference)
10.52	Purchase Agreement, dated May 14, 2012, among Kodiak Oil & Gas Corp., Kodiak Oil & Gas (USA) Inc., and RBC Capital Markets, LLC, Wells Fargo Securities, LLC, and Credit Suisse Securities (USA) LLC, as representatives of the several purchasers identified therein (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 17, 2012 and incorporated herein by reference)
10.53	Purchase Agreement, dated January 10, 2013, among Kodiak Oil & Gas Corp., Kodiak Oil & Gas (USA) Inc., and Wells Fargo Securities, LLC, RBC Capital Markets, LLC and Credit Suisse Securities (USA) LLC, as representatives of the several purchasers identified therein (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on January 15, 2013 and incorporated herein by reference)
12.1	Computation of Ratio of Earnings to Fixed Charges
16.1	Letter from Hein & Associates LLP, Independent Registered Public Accounting Firm, to the Securities and Exchange Commission dated April 5, 2011, regarding change in certifying accountant (filed as Exhibit 16.1 to the registrant's Current Report on Form 8-K filed on April 5, 2011 and incorporated herein by reference)
21.1	Subsidiaries of the Registrant
23.1	Consent of Ernst & Young LLP
23.2	Consent of Hein & Associates LLP

Exhibit Number	Description
23.3	Consent of Netherland Sewell & Associates, Inc.
31.1	Certification of the Chief Executive Officer required by Rule 13a-14(a) or Rule 15d-14(a)
31.2	Certification of the Chief Financial Officer required by Rule 13a-14(a) or Rule 15d-14(a)
32.1	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350
32.2	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350
99.1	Reserve Estimate Report of Netherland Sewell & Associates, Inc.
101	The following materials are filed herewith: (i) XBRL Instance, (ii) XBRL Taxonomy Extension Schema, (iii) XBRL Taxonomy Extension Calculation, (iv) XBRL Taxonomy Extension Labels, (v) XBRL Taxonomy Extension Presentation, and (vi) XBRL Taxonomy Extension Definition. In accordance with Rule 406T of Regulation S-T, the information in these exhibits is furnished and deemed not filed or a part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Exchange Act of 1934, and otherwise is not subject to liability under these sections and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933, as amended, except as expressly set forth by the specific reference in such filing.

GLOSSARY OF CRUDE OIL AND NATURAL GAS TERMS

The following technical terms defined in this section are used throughout this Form 10-K:

"Bbl" means one stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

"Bcf" means one billion cubic feet of natural gas.

"BOE" means barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

"BOE/d" means BOE per day.

"Btu" means one British thermal unit - a measure of the amount of energy required to raise the temperature of a one-pound mass of water one degree Fahrenheit at sea level.

"Completion" means the installation of permanent equipment for the production of oil or natural gas.

"Delay rental" means a payment made to the lessor under a non-producing oil and natural gas lease at the end of each year to continue the lease in force for another year during its primary term.

"Developed acreage" means the number of acres that are allocated or assignable to producing wells or wells capable of production.

"Development well" means a well drilled to a known producing formation in a previously discovered field, usually offsetting a producing well on the same or an adjacent oil and natural gas lease.

"Dry hole" means a well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

"EUR" means estimated ultimate recovery. EUR is an approximation of the quantity of oil or gas that is potentially recoverable or has already been recovered from a reserve or well.

"Exploratory well" means a well drilled either (a) in search of a new and as yet undiscovered pool of oil or gas or (b) with the hope of significantly extending the limits of a pool already developed (also known as a "wildcat well").

"Federal Unit" means acreage under federal oil and natural gas leases subject to an agreement or plan among owners of leasehold interests, which satisfies certain minimum arrangements and has been approved by an authorized representative of the U.S. Secretary of the Interior, to consolidate under a cooperative unit plan or agreement for the development of such acreage comprising a common oil and natural gas pool, field or like area, without regard to separate leasehold ownership of each participant and providing for the sharing of costs and benefits on a basis as defined in such agreement or plan under the supervision of a designated operator.

"Field" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

"Fracturing" means mechanically inducing a crack or surface of breakage within rock not related to foliation or cleavage in metamorphic rock in order to enhance the permeability of rocks greatly by connecting pores together.

"Gas" or *"Natural gas"* means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain liquids.

"Gross Acres" or *"Gross Wells"* means the total acres or wells, as the case may be, in which we have a working interest.

"Hydraulic fracturing" means a procedure to stimulate production by forcing a mixture of fluid and proppant (usually sand) into the formation under high pressure. This creates artificial fractures in the reservoir rock, which increases permeability and porosity.

"Horizontal drilling" means a well bore that is drilled laterally.

"Landowner royalty" means that interest retained by the holder of a mineral interest upon the execution of an oil and natural gas lease which usually amounts to $^1/_8$ of all gross revenues from oil and natural gas production unencumbered with any expenses of operation, development, or maintenance.

"Leases" means full or partial interests in oil or gas properties authorizing the owner of the lease to drill for, produce and sell oil and natural gas in exchange for any or all of rental, bonus and royalty payments. Leases are generally acquired from private landowners (fee leases) and from federal and state governments on acreage held by them.

"MBbl" One thousand barrels of crude oil, condensate or natural gas liquids.

"Mcf" is an abbreviation for "1,000 cubic feet," which is a unit of measurement of volume for natural gas.

"Net Acres" or "Net Wells" is the sum of the fractional working interests owned in gross acres or wells, as the case may be, expressed as whole numbers and fractions thereof.

"Net revenue interest" means all of the working interests less all royalties, overriding royalties, non-participating royalties, net profits interest or similar burdens on or measured by production from oil and natural gas.

"NYMEX" means New York Mercantile Exchange.

"Overriding royalty" means an interest in the gross revenues or production over and above the landowner's royalty carved out of the working interest and also unencumbered with any expenses of operation, development or maintenance.

"Operator" means the individual or company responsible to the working interest owners for the exploration, development and production of an oil or natural gas well or lease.

"Play" means a regionally distributed oil and natural gas accumulation as opposed to conventional plays which are more limited in their area extent. Resource plays are characterized by continuous, aerially extensive hydrocarbon accumulations in tight sand, shale and coal reservoirs.

"Prospect" means a geological area which is believed to have the potential for oil and natural gas production.

"PV-10 value" means the present value of estimated future gross revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date indicated (unless such prices or costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, discounted using an annual discount rate of 10 percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure calculation, it does provide an indicative representation of the relative value of the Company on a comparative basis to other companies and from period to period.

"Productive well" means a well that is producing oil or gas or that is capable of production.

"Proved developed reserves" means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"Proved reserves" means the estimated quantities of oil, gas and gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

"Proved undeveloped reserves" means reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

"Recompletion" means the completion for production from an existing wellbore in a formation other than that in which the well has previously been completed.

"Reserve life" represents the estimated net proved reserves at a specified date divided by actual production for the preceding 12-month period.

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

"Royalty" means the share paid to the owner of mineral rights, expressed as a percentage of gross income from oil and natural gas produced and sold unencumbered by expenses relating to the drilling, completing and operating of the affected well.

"Royalty interest" means an interest in an oil and natural gas property entitling the owner to shares of oil and natural gas production, free of costs of exploration, development and production operations.

"Seismic Data" means an exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of a subsurface rock formation. 2-D seismic provides two-dimensional information and 3-D seismic provides three-dimensional views.

"Spacing" means the distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

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

"Undeveloped leasehold acreage" means the leased acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains estimated net proved reserves.

"Unit" means the joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"Working interest" means an interest in an oil and natural gas lease entitling the holder at its expense to conduct drilling and production operations on the leased property and to receive the net revenues attributable to such interest, after deducting the landowner's royalty, any overriding royalties, production costs, taxes and other costs.

"WTI" means the price of West Texas Intermediate crude oil on the NYMEX.

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.

KODIAK OIL & GAS CORP.
(Registrant)

Date: February 28, 2013

By: /s/ LYNN A. PETERSON
Lynn A. Peterson
President and Chief Executive Officer
(principal 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.

By:	/s/ LYNN A. PETERSON Lynn A. Peterson	President and Chief Executive Officer (principal executive officer)	February 28, 2013
By:	/s/ JAMES E. CATLIN James E. Catlin	Executive Vice President	February 28, 2013
By:	/s/ JAMES P. HENDERSON James P. Henderson	Executive Vice President and Chief Financial Officer (principal financial officer and principal accounting officer)	February 28, 2013
By:	/s/ HERRICK K. LIDSTONE, JR. Herrick K. Lidstone, Jr.	Director	February 28, 2013
By:	/s/ RODNEY D. KNUTSON Rodney D. Knutson	Director	February 28, 2013
By:	/s/ WILLIAM J. KRYSIAK William J. Krysiak	Director	February 28, 2013

DIRECTORS AND OFFICERS

Lynn A. Peterson
President, Chief Executive Officer
and Chairman of the Board of Directors

James P. Henderson
Executive Vice President of Finance,
Chief Financial Officer, Secretary and Treasurer

James E. Catlin
Executive Vice President of Business Development
and Director

Russ D. Cunningham
Executive Vice President of Exploration

Russell A. Branting
Executive Vice President of Operations

Rodney D. Knutson *
Director, Attorney in Aspen, Colorado

Herrick K. Lidstone, Jr. *
Director, Attorney with Burns, Figa & Will, P.C.

William Krysiak, CPA *
Director, Chief Financial Officer of Southwest
Generation Operating Company, LLC

* Member of the Audit, Compensation
and Nominating and Corporate Governance
Committees

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Legal Counsel
Dorsey & Whitney LLP
Seattle, Washington USA

Miller Thompson LLP
Vancouver, British Columbia Canada

Independent Reservoir Engineer
Netherland, Sewell & Associates, Inc.
Dallas, TX USA

CORPORATE INFORMATION

Stock Exchange Listing
NYSE: "KOG"

Registrar and Transfer Agent
Computershare Investor Services, Inc.
100 University Ave., 9^{th} Floor, North Tower
Toronto, Ontario M5J 2Y1 Canada

Contact transfer agent for information regarding changes of address, registration of shares, transfers or lost certificates, or for information about your shareholder account.

Form 10-K

The enclosed Form 10-K of the company does not include the exhibits that were filed with the U.S. Securities and Exchange Commission. A complete copy of the form 10-K, including all exhibits, may be obtained by writing to the Company or may be accessed on Kodiak's website at www.kodiakog.com

Code of Business Conduct and Ethics

Please reference the Corporate Governance section on Kodiak's website at www.kodiakog.com for important information regarding the Company's Code of Business Conduct and Ethics. Additionally a copy may be obtained by writing to the Company.

Annual Meeting
Kodiak's annual general meeting will be held at:

The Denver Athletic Club
Centennial Room
1325 Glenarm Place
Denver, Colorado 80204
Date: June 19, 2013
Time: 9:00 AM Mountain Daylight Time