WHITING PETROLEUM CORP
Form 10-K
February 28, 2014

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

FORM 10-K

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

For the fiscal year ended December 31, 2013

or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _______________ to _______________

Commission file number: 001-31899

WHITING PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	20-0098515 (I.R.S. Employer Identification No.)
1700 Broadway, Suite 2300 Denver, Colorado (Address of principal executive offices)	80290-2300 (Zip code)

(303) 837-1661
(Registrant's telephone number, including area code)

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

Common Stock, $0.001 par value	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange
(Title of Class)	(Name of each exchange on which registered)

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 T No £

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Act. Yes £ No T

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 T 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 T No £

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

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

Large accelerated filerT Accelerated filer£ Non-accelerated filer£ Smaller reporting company£

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

Aggregate market value of the voting common stock held by non-affiliates of the registrant at June 30, 2013: $5,481,981,242.

Number of shares of the registrant's common stock outstanding at February 14, 2014: 118,956,489 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2014 Annual Meeting of Stockholders are incorporated by reference into Part III.

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GLOSSARY OF CERTAIN DEFINITIONS

Unless the context otherwise requires, the terms “we,” “us,” “our” or “ours” when used in this Annual Report on Form 10-K refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries. When the context requires, we refer to these entities separately.

We have included below the definitions for certain terms used in this Annual Report on Form 10-K:

“3-D seismic” Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

“Bbl” One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil, NGLs and other liquid hydrocarbons.

“Bcf” One billion cubic feet of natural gas.

“BOE” One stock tank barrel of oil equivalent, computed on an approximate energy equivalent basis that one Bbl of crude oil equals six Mcf of natural gas and one Bbl of crude oil equals one Bbl of natural gas liquids.

“CO2” Carbon dioxide.

“CO2 flood” A tertiary recovery method in which CO2 is injected into a reservoir to enhance hydrocarbon recovery.

“completion” The installation of permanent equipment for the production of crude oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

“costless collar” An options position where the proceeds from the sale of a call option at its inception fund the purchase of a put option at its inception.

“differential” The difference between a benchmark price of oil and natural gas, such as the NYMEX crude oil spot, and the wellhead price received.

“deterministic method” The method of estimating reserves or resources using a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation.

“development well” A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

“exploratory well” A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well.

“extension well” A well drilled to extend the limits of a known reservoir.

“FASB” Financial Accounting Standards Board.

“FASB ASC” The Financial Accounting Standards Board Accounting Standards Codification.

"field" An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc.

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“GAAP” Generally accepted accounting principles in the United States of America.

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

“ISDA” International Swaps and Derivatives Association, Inc.

“lease operating expense” or “LOE” The expenses of lifting oil or gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs and other expenses incidental to production, but not including lease acquisition or drilling or completion expenses.

“LIBOR” London interbank offered rate.

“MBbl” One thousand barrels of oil or other liquid hydrocarbons.

“MBbl/d” One MBbl per day.

“MBOE” One thousand BOE.

“MBOE/d” One MBOE per day.

“Mcf” One thousand cubic feet of natural gas.

“MMBbl” One million Bbl.

“MMBOE” One million BOE.

“MMBtu” One million British Thermal Units.

“MMcf” One million cubic feet of natural gas.

“MMcf/d” One MMcf per day.

“net production” The total production attributable to our fractional working interest owned.

“NGL” Natural gas liquid.

“NYMEX” The New York Mercantile Exchange.

“PDNP” Proved developed nonproducing reserves.

“PDP” Proved developed producing reserves.

“plug-and-perf technology” A horizontal well completion technique in which hydraulic fractures are performed in multiple stages, with each stage utilizing a bridge plug to divert fracture stimulation fluids through the perforations in the formation within that stage.

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

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"possible reserves" Those reserves that are less certain to be recovered than probable reserves.

"pre-tax PV10%" The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with the guidelines of the SEC, net of estimated lease operating expense, production taxes and future development costs, using costs as of the date of estimation without future escalation and using an average of the first-day-of-the month price for each of the 12 months within the fiscal year, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, or federal income taxes and discounted using an annual discount rate of 10%. Pre-tax PV10% may be considered a non-GAAP financial measure as defined by the SEC. See the footnote to the Proved Reserves table in Item 1. "Business" of this Annual Report on Form 10-K for more information.

"probable reserves" Those reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

"proved developed reserves" Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

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

The area of the reservoir considered as proved includes all of the following:

a. The area identified by drilling and limited by fluid contacts, if any, and

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

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

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

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

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

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"proved undeveloped reserves" Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are schedule to be drilled within five years, unless specific circumstances justify a longer time. Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

"PUD" Proved undeveloped reserves.

"reasonable certainty" If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical and geochemical) engineering, and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

"recompletion" An operation whereby a completion in one zone is abandoned in order to attempt a completion in a different zone within the existing wellbore.

"reserves" Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

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

"resource play" Refers to drilling programs targeted at regionally distributed oil or natural gas accumulations. Successful exploitation of these reservoirs is dependent upon new technologies such as horizontal drilling and multi-stage fracture stimulation to access large rock volumes in order to produce economic quantities of oil or natural gas.

"royalty" The amount or fee paid to the owner of mineral rights, expressed as a percentage or fraction of gross income from crude oil or natural gas produced and sold, unencumbered by expenses relating to the drilling, completing or operating of the affected well.

"royalty interest" An interest in an oil or natural gas property entitling the owner to shares of the crude oil or natural gas production free of costs of exploration, development and production operations.

"SEC" The United States Securities and Exchange Commission.

"service well" A service well is a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation or injection for in-situ combustion.

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“standardized measure of discounted future net cash flows” The discounted future net cash flows relating to proved reserves based on the average price during the 12-month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period (unless prices are defined by contractual arrangements, excluding escalations based upon future conditions); current costs and statutory tax rates (to the extent applicable); and a 10% annual discount rate.

“working interest” The interest in a crude oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

“workover” Operations on a producing well to restore or increase production.

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PART I

Item 1. Business

Overview

We are an independent oil and gas company engaged in exploration, development, acquisition and production activities primarily in the Rocky Mountains and Permian Basin regions of the United States. We were incorporated in 2003 in connection with our initial public offering.

Since our inception in 1980, we have built a strong asset base and achieved steady growth through property acquisitions, development and exploration activities. As of December 31, 2013, our estimated proved reserves totaled 438.5 MMBOE, representing a 16% increase in our proved reserves since December 31, 2012. Our 2013 average daily production was 94.1 MBOE/d and results in an average reserve life of approximately 12.8 years.

The following table summarizes by core area, our estimated proved reserves as of December 31, 2013, their corresponding pre-tax PV10% values, and our fourth quarter 2013 average daily production rates, as well as our company's total standardized measure of discounted future net cash flows as of December 31, 2013:

	Proved Reserves (1)						
Core Area	Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% Oil	Pre-Tax PV10% Value (2) (in millions)	4th Quarter 2013 Average Daily Production (MBOE/d)
Rocky Mountains	236.6	25.7	208.8	297.0	80%	$ 7,309.7	84.7
Permian Basin	106.4	17.8	17.6	127.1	84%	1,524.6	12.3
Other (3)	4.4	1.4	51.1	14.4	31%	159.7	4.0
Total	347.4	44.9	277.5	438.5	79%	$ 8,994.0	101.0
Discounted Future Income Taxes						(2,400.1)	
Standardized Measure of Discounted Future Net Cash Flows						$ 6,593.9	

(1) Oil and gas reserve quantities and related discounted future net cash flows have been derived from oil and gas prices calculated using an average of the first-day-of-the month price for each month within the 12 months ended December 31, 2013, pursuant to current SEC and FASB guidelines.

(2) Pre-tax PV10% may be considered a non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Pre-tax PV10% is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting future income

taxes. We believe pre-tax PV10% is a useful measure for investors for evaluating the relative monetary significance of our oil and natural gas properties. We further believe investors may utilize our pre-tax PV10% as a basis for comparison of the relative size and value of our proved reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. Our management uses this measure when assessing the potential return on investment related to our oil and gas properties and acquisitions. However, pre-tax PV10% is not a substitute for the standardized measure of discounted future net cash flows. Our pre-tax PV10% and the standardized measure of discounted future net cash flows do not purport to present the fair value of our proved oil, NGL and natural gas reserves.

(3) Other primarily includes oil and gas properties in Arkansas, Louisiana, Michigan, Oklahoma and Texas.

While historically we have grown through acquisitions, we are increasingly focused on a balance between our exploration and development programs and are continuing to selectively pursue acquisitions that complement our existing core properties. We believe that our significant drilling inventory, combined with our operating experience and cost structure, provides us with meaningful organic growth opportunities.

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Our growth plan is centered on the following activities:

- pursuing the development of projects that we believe will generate attractive rates of return;
- allocating a portion of our exploration and development (“E&D”) budget to leasing and exploring prospect areas;
- maintaining a balanced portfolio of lower risk, long-lived oil and gas properties that provide stable cash flows; and
- seeking property acquisitions that complement our core areas.

During 2013, we incurred $2,896.1 million in exploration, development and cash acquisition capital expenditures, including $2,398.4 million for the drilling of 428 gross (229.2 net) wells. Of these new wells, 220.7 (net) resulted in productive completions and 8.5 (net) were unsuccessful, yielding a 96% success rate.

Our current 2014 E&D budget is $2.7 billion, and included in this amount is approximately $116.0 million in acreage acquisition costs. The 2014 budget of $2.7 billion represents a slight increase from the $2,675.2 million in E&D (which consisted of exploration, development and acreage expenditures) we incurred in 2013. We expect to fund substantially all of our 2014 E&D budget using net cash provided by operating activities, cash on hand and borrowings under our credit facility.

We continually evaluate our current portfolio and sell properties when we believe that the sales price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own.

Acquisitions and Divestitures

The following is a summary of our acquisitions and divestitures during the last two years. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in Item 7 of this Annual Report on Form 10-K for more information on these acquisitions and divestitures.

2013 Acquisitions. On September 20, 2013, we completed the acquisition of approximately 39,300 gross (17,300 net) acres, including interests in 121 producing oil and gas wells and undeveloped acreage, in the Williston Basin in Williams and McKenzie counties of North Dakota and Roosevelt and Richland counties of Montana for an aggregate unadjusted purchase price of $260.0 million.

2013 Divestitures. On October 31, 2013, we completed the sale of approximately 45,000 gross (32,200 net) acres, including our interests in certain producing oil and gas wells and undeveloped acreage, in our Big Tex prospect located in the Delaware Basin for a cash purchase price of $152.0 million (subject to post-closing adjustments), resulting in a pre-tax gain on sale of $13.0 million. Of the total net acres sold, approximately 30,800 net acres are located in Pecos County, Texas, and approximately 1,400 net acres are located in Reeves County, Texas. The producing properties had estimated proved reserves of 1.1 MMBOE as of December 31, 2012, representing 0.3% of our proved reserves as of that date, and generated 0.2 MBOE/d of our third quarter 2013 average daily net production.

On July 15, 2013, we completed the sale of our interests in certain oil and gas producing properties located in our enhanced oil recovery projects in the Postle and Northeast Hardesty fields in Texas County, Oklahoma, including the related Dry Trail plant gathering and processing facility, oil delivery pipeline, our entire 60% interest in the Transpetco CO2 pipeline, crude oil swap contracts and certain other related assets and liabilities (collectively the “Postle Properties”) for a cash purchase price of $809.7 million after selling costs and post-closing adjustments, resulting in a pre-tax gain on sale of $109.7 million. We used the net proceeds from this sale to repay a portion of the debt outstanding under our credit agreement. The Postle Properties consisted of estimated proved reserves of 45.1

MMBOE as of December 31, 2012, representing 11.9% of our proved reserves as of that date, and generated 8% (or 7.6 MBOE/d) of our June 2013 average daily net production.

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2012 Acquisitions. On March 22, 2012, we completed the acquisition of approximately 13,300 net undeveloped acres in the Missouri Breaks field in Richland County, Montana for $33.3 million.

2012 Divestitures. On May 18, 2012, we sold a 50% ownership interest in our Belfield gas processing plant, natural gas gathering system, oil gathering system and related facilities located in Stark County, North Dakota for total cash proceeds of $66.2 million. We used the net proceeds from the sale to repay a portion of the debt outstanding under our credit agreement.

On March 28, 2012, we completed an initial public offering of units of beneficial interest in Whiting USA Trust II ("Trust II"), selling 18,400,000 Trust II units at $20.00 per unit, which generated net proceeds of $322.3 million after underwriters' fees, offering expenses and post-close adjustments. We used the net offering proceeds to repay a portion of the debt outstanding under our credit agreement. The net proceeds from the sale of Trust II units to the public resulted in a deferred gain on sale of $128.2 million. Immediately prior to the closing of the offering, we conveyed a term net profits interest in certain of our oil and gas properties to Trust II in exchange for 100% of the trust's units issued, or 18,400,000 units.

The net profits interest entitles Trust II to receive 90% of the net proceeds from the sale of oil and natural gas production from the underlying properties. The net profits interest will terminate on the later to occur of (1) December 31, 2021, or (2) the time when 11.79 MMBOE have been produced from the underlying properties and sold. This is the equivalent of 10.61 MMBOE in respect of Trust II's right to receive 90% of the net proceeds from such reserves pursuant to the net profits interest. The conveyance of the net profits interest to Trust II consisted entirely of proved reserves of 10.61 MMBOE as of the January 1, 2012 effective date, representing 3% of our proved reserves as of December 31, 2011 and 5% (or 4.5 MBOE/d) of our March 2012 average daily net production.

Business Strategy

Our goal is to generate meaningful growth in our net asset value per share of proved reserves through the exploration, development and acquisition of oil and gas projects with attractive rates of return on capital employed. To date, we have pursued this goal through both continued field development in our core areas and the acquisition of reserves. Because of our extensive property base, we are pursuing several economically attractive oil and gas opportunities to develop properties as well as explore our acreage positions for additional production growth and proved reserves. Specifically, we have focused, and plan to continue to focus, on the following:

Pursuing High-Return Organic Reserve Additions. The development of large resource plays such as our Williston Basin project has become one of our central objectives. As of December 31, 2013, we have assembled approximately 1,147,500 gross (715,000 net) developed and undeveloped acres in the Williston Basin located in Montana and North Dakota. As of December 31, 2013, we had 18 drilling rigs operating in the Williston Basin. During 2013, the focus of our development in the Williston Basin continued in the Sanish, Lewis & Clark/Pronghorn, Hidden Bench/Tarpon, Missouri Breaks and Cassandra fields. Additionally, Whiting owns a 50% ownership interest in two gas processing plants located in the Williston Basin. The Robinson Lake plant located in our Sanish field has a current processing capacity of approximately 90 MMcf/d, and we have projects underway to increase this processing capability to 110 MMcf/d by mid-year 2014. Our Belfield Plant located near the Pronghorn field has a processing capacity of 35 MMcf/d. Both plants have fractionation capability to convert NGLs into propane and butane, which end products can then be sold locally for higher realized prices.

A new area of focus for us is our Redtail field in the Denver Julesberg Basin ("DJ Basin") in Weld County, Colorado, where we have the potential to drill over 1,000 gross wells targeting several intervals in the Niobrara formation. As of December 31, 2013, we had approximately 169,700 gross (122,300 net) acres, with three drilling rigs operating in this area. We are nearing the completion of a gas processing plant in Weld County, Colorado with an initial processing capacity of 15 MMcf/d, which will process production from our Redtail field. We expect our Redtail field will be another growth platform for Whiting in 2014 and beyond.

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Developing Existing Properties. Our current property base, which includes our acquisitions over the past ten years, provides us with numerous low-risk opportunities for exploration and development drilling. As of December 31, 2013, we have identified a drilling inventory of over 3,200 gross wells that we believe will add substantial production over the next five years. Our drilling inventory consists of the development of our proved and unproved reserves. Additionally, we have opportunities to apply and expand enhanced recovery techniques that we expect will increase proved reserves and extend the productive lives of our mature fields. In 2005, we acquired the North Ward Estes field, located in the Permian Basin of West Texas. We have experienced significant production increases in this field through the use of secondary and tertiary recovery techniques, and we anticipate such production increases will continue over the next five to seven years. In this field, we are actively injecting water and CO2 and executing extensive re-development, drilling and completion operations, as well as expanding our gas processing facilities, which will allow us to separate and inject approximately 295 MMcf/d of recycled CO2, thereby maximizing our recovery of oil and gas from this reservoir.

Growing Through Accretive Acquisitions. From 2004 to 2013, we completed 17 separate significant acquisitions of producing properties for estimated proved reserves of 248.0 MMBOE, as of the effective dates of the acquisitions. Our experienced team of management, land, engineering and geoscience professionals has developed and refined an acquisition program designed to increase reserves and complement our existing properties, including identifying and evaluating acquisition opportunities, closing purchases and then effectively managing properties we acquire. We intend to selectively pursue the acquisition of properties complementary to our core operating areas.

Disciplined Financial Approach. Our goal is to remain financially strong, yet flexible, through the prudent management of our balance sheet and active management of commodity price volatility. We have historically funded our acquisitions and growth activity through a combination of equity and debt issuances, bank borrowings, internally generated cash flow and certain oil and gas divestitures, as appropriate, to maintain our strong financial position. From time to time, we monetize non-core properties and use the net proceeds from these asset sales to repay debt under our credit agreement, as we did with the sale of our Postle Properties, which we completed on July 15, 2013. To support cash flow generation on our existing properties and help ensure expected cash flows from acquired properties, we periodically enter into derivative contracts. Typically, we use costless collars and fixed price gas contracts to provide an attractive base commodity price level.

Competitive Strengths

We believe that our key competitive strengths lie in our balanced asset portfolio, our experienced management and technical team and our commitment to the effective application of new technologies.

Balanced, Long-Lived Asset Base. As of December 31, 2013, we had interests in 10,476 gross (3,922 net) productive wells across approximately 1,387,200 gross (751,700 net) developed acres across all our geographical areas. We believe this geographic mix of properties and organic drilling opportunities, combined with our continuing business strategy of acquiring and developing properties in these areas, presents us with multiple opportunities to execute our strategy. Our proved reserve life is approximately 12.8 years based on year-end 2013 proved reserves and 2013 production.

Experienced Management Team. Our management team averages 28 years of experience in the oil and gas industry. Our personnel have extensive experience in each of our core geographical areas and in all of our operational disciplines. In addition, each of our acquisition professionals has at least 29 years of experience in the evaluation, acquisition and operational assimilation of oil and gas properties.

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Commitment to Technology. In each of our core operating areas, we have accumulated extensive geologic and geophysical knowledge and have developed significant technical and operational expertise. In recent years, we have developed considerable expertise in conventional and 3-D seismic imaging and interpretation. Our technical team has access to approximately 12,100 square miles of 3-D seismic data, digital well logs and other subsurface information. This data is analyzed with advanced geophysical and geological computer resources dedicated to the accurate and efficient characterization of the subsurface oil and gas reservoirs that comprise our asset base. In addition, our information systems enable us to update our production databases through daily uploads from hand-held computers in the field. We have a team of 10 professionals averaging over 25 years of experience managing CO2 floods, which provides us with the ability to pursue other CO2 flood targets and employ this technology to add reserves to our portfolio. This commitment to technology has increased the productivity and efficiency of our field operations and development activities.

In 2011, we completed the build-out and installation of an in-house, state-of-the-art rock analysis laboratory. We continue to utilize the data from this rock lab to support real-time drilling and completion decisions. In addition, it has helped us to further understand unconventional oil plays, which has given us the confidence to assemble over 600,000 gross acres in three new oil resource plays, located in three separate basin areas that are new to us.

During 2013, we tested several different modifications to our completion techniques, including varying the number of completion stages, utilizing different fracture stimulation fluids and increasing the volume of sand and ceramic proppant used in these fluids. As we continued to refine our process, our well completions in several of our development areas have evolved to utilize cemented liners and plug-and-perf technology to deliver improved results. In 2014, we plan to utilize this technique on a majority of the wells we drill in the Williston Basin. We have also tested this completion technique in the Niobrara formation in the DJ Basin of Colorado and the Delaware Basin of West Texas with encouraging results. We continue to refine our completion techniques to deliver improved results across all of our fields.

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Proved, Probable and Possible Reserves

Our estimated proved, probable and possible reserves as of December 31, 2013 are summarized in the table below. See “Reserves” in Item 2 of this Annual Report on Form 10-K for information relating to the uncertainties surrounding these reserve categories.

Rocky Mountains:	Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% of Total Proved	Estimated Future Capital Expenditures (in millions)
PDP	128.5	13.2	122.1	161.9	55 %	
PDNP	0.5	0.1	1.2	0.8	- %	
PUD	107.6	12.4	85.5	134.3	45 %	
Total proved	236.6	25.7	208.8	297.0	100 %	$ 2,597.7
Total probable	90.8	17.4	215.3	144.1		$ 2,835.7
Total possible	59.0	8.4	136.2	90.1		$ 1,866.2
Permian Basin:						
PDP	49.6	5.9	11.8	57.4	45 %	
PDNP	15.3	3.5	2.8	19.3	15 %	
PUD	41.5	8.4	3.0	50.4	40 %	
Total proved	106.4	17.8	17.6	127.1	100 %	$ 1,335.3
Total probable	15.9	4.3	34.6	26.0		$ 265.1
Total possible	76.9	16.1	2.8	93.4		$ 739.8
Other (1):						
PDP	3.6	0.8	38.7	11.0	76 %	
PDNP	0.7	0.3	6.6	2.1	15 %	
PUD	0.1	0.3	5.8	1.3	9 %	
Total proved	4.4	1.4	51.1	14.4	100 %	$ 21.4
Total probable	2.6	0.6	17.7	6.1		$ 57.1
Total possible	1.3	0.1	24.8	5.6		$ 80.1
Total Company:						
PDP	181.7	19.9	172.6	230.3	53 %	
PDNP	16.5	3.9	10.6	22.2	5 %	
PUD	149.2	21.1	94.3	186.0	42 %	
Total proved	347.4	44.9	277.5	438.5	100 %	$ 3,954.4
Total probable	109.3	22.3	267.6	176.2		$ 3,157.9
Total possible	137.2	24.6	163.8	189.1		$ 2,686.1

(1) Other primarily includes oil and gas properties in Arkansas, Louisiana, Michigan, Oklahoma and Texas.

The estimated future capital expenditures in the table above incorporate numerous assumptions and are subject to many uncertainties, including oil and natural gas prices, costs of oil field goods and services, drilling results and several other factors.

Marketing and Major Customers

We principally sell our oil and gas production to end users, marketers and other purchasers that have access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is trucked to storage facilities. The table below presents percentages by purchaser that accounted for 10% or more of our total oil, NGL and natural gas sales for the years ended December 31, 2013, 2012 and 2011. We believe that the loss of any individual purchaser would not have a long-term material adverse impact on our financial position or results of operations.

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	2013	2012	2011
Plains Marketing LP	21%	20%	27%
Shell Trading US	14%	14%	13%
Eighty Eight Oil Company	11%	11%	8%
Bridger Trading LLC	8%	11%	6%

Title to Properties

Our properties are subject to customary royalty interests, liens under indebtedness, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. Our credit agreement is also secured by a first lien on substantially all of our assets. We do not believe that any of these burdens materially interfere with the use of our properties or the operation of our business.

We believe that we have satisfactory rights or title to all of our producing properties. As is customary in the oil and gas industry, limited investigation of title is made at the time of acquisition of undeveloped properties. In most cases, we investigate title and obtain title opinions from counsel only when we acquire producing properties or before commencement of drilling operations.

Competition

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for available investment capital in the oil and gas industry.

Regulation

Regulation of Transportation, Sale and Gathering of Natural Gas

The Federal Energy Regulatory Commission (the "FERC") regulates the transportation, and to a lesser extent, the sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 and regulations issued under those Acts. In 1989, however, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and non-price controls affecting wellhead sales of natural gas, effective January 1, 1993. While sales by producers of natural gas and all sales of crude oil, condensate and NGLs can currently be made at unregulated market prices, in the future Congress could reenact price controls or enact other legislation with detrimental impact on many aspects of our business.

Our natural gas sales are affected by the availability, terms and cost of transportation. The price and terms of access to pipeline transportation and underground storage are subject to extensive federal and state regulation. From 1985 to the present, several major regulatory changes have been implemented by Congress and the FERC that affect the economics of natural gas production, transportation and sales. In addition, the FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry that remain subject to the FERC's jurisdiction, most notably interstate natural gas transmission companies and certain underground storage facilities. These initiatives may also affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis.

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The FERC implemented The Outer Continental Shelf Lands Act pertaining to transportation and pipeline issues, which requires that all pipelines operating on or across the outer continental shelf provide open access and non-discriminatory transportation service. One of the FERC's principal goals in carrying out this Act's mandate is to increase transparency in the market to provide producers and shippers on the outer continental shelf with greater assurance of open access services on pipelines located on the outer continental shelf and non-discriminatory rates and conditions of service on such pipelines.

We cannot accurately predict whether the FERC's actions will achieve the goal of increasing competition in the markets in which our natural gas is sold. In addition, many aspects of these regulatory developments have not become final but are still pending judicial and final FERC decisions. Regulations implemented by the FERC in recent years could result in an increase in the cost of transportation service on certain petroleum product pipelines. In addition, the natural gas industry historically has always been heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Transportation and safety of natural gas is subject to regulation by the Department of Transportation (the "DOT") under the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2012. In addition, intrastate natural gas transportation is subject to enforcement by state regulatory agencies, and the Pipeline and Hazardous Material Safety Administration ("PHMSA"), an agency within the DOT, enforces regulations on interstate natural gas transportation. State regulatory agencies can also create their own transportation and safety regulations as long as they meet PHMSA's minimum requirements. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any of the states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Likewise, the effect of regulatory changes by the DOT and their effect on interstate natural gas transportation will not affect our operations in any way that is of material difference from those of our competitors. We use the latest tools and technologies to remain compliant with current pipeline safety regulations.

Regulation of Transportation of Oil

Sales of crude oil, condensate and NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted, and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for crude oil transportation rates that allowed for an increase or decrease in the cost of transporting oil to the purchaser. The FERC's regulations include a methodology for oil pipelines to change their rates through the use of an index system that establishes ceiling levels for such rates. The most recent mandatory five-year review period resulted in an order from the FERC for the index to be based on Producer Price Index for Finished Goods (the "PPI-FG"), plus a 2.65% adjustment, for the five-year period July 1, 2011 through June 30, 2016. This represents an increase for the PPI-FG plus 1.3% adjustment from the prior five-year period. A requested rehearing of the order was denied by the FERC. The regulations provide that each year the Commission will publish the oil pipeline index after the PPI-FG becomes available. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

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Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. In addition, the FERC has emergency authority under the Interstate Commerce Act to intervene and direct priority use of oil pipeline transportation capacity, and the FERC has exercised this authority over a specific pipeline in February 2014 in response to significant disruptions in the supply of propane. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Transportation and safety of oil and hazardous liquid is subject to regulation by the DOT under the Pipeline Integrity, Protection, Enforcement and Safety Act of 2006 and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2012. PHMSA enforces regulations on all interstate liquids transportation and some intrastate liquids transportation. PHMSA does not enforce the regulations in states that are capable of enforcing the same regulations themselves. The effect of regulatory changes under the DOT and their effect on interstate and intrastate oil and hazardous liquid transportation will not affect our operations in any way that is of material difference from those of our competitors.

Regulation of Production

The production of oil and gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and periodic report submittals during operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum allowable rates of production from oil and gas wells, the regulation of well spacing and the plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and gas that we can produce from our wells and to limit the number of wells or the locations that we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production or sale of oil, NGLs and natural gas within its jurisdiction.

Some of our offshore operations are conducted on federal leases that are administered by the Bureau of Ocean Energy Management (the "BOEM"). Currently, only 0.1% of our total production volumes are produced from offshore leases. However, the present value of our future abandonment obligations associated with offshore properties was \$32.8 million as of December 31, 2013. Whiting is therefore required to comply with the regulations and orders issued by the BOEM under the Outer Continental Shelf Lands Act. Among other things, we are required to obtain prior BOEM approval for any exploration plans we pursue and for our lease development and production plans. BOEM regulations also establish construction requirements for production facilities located on our federal offshore leases and govern the plugging and abandonment of wells and the removal of production facilities from these leases. Under limited circumstances, the BOEM could require us to suspend or terminate our operations on a federal lease.

The BOEM also establishes the basis for royalty payments due under federal oil and gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and gas leases. The basis for royalty payments established by the BOEM and the state regulatory authorities is generally applicable to all federal and state oil and gas lessees. Accordingly, we believe that the impact of royalty regulation on our operations should generally be the same as the impact on our competitors.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

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Environmental Regulations

General. Our oil and gas exploration, development and production operations are subject to stringent federal, state and local laws and regulations governing the discharge or release of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency (the "EPA") issue regulations to implement and enforce such laws, which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties or that may result in injunctive relief for failure to comply. These laws and regulations may require the acquisition of a permit before drilling or facility construction commences; restrict the types, quantities and concentrations of various materials that can be released into the environment in connection with drilling and production activities; limit or prohibit project siting, construction or drilling activities on certain lands located within wilderness, wetlands, ecologically sensitive and other protected areas; require remedial action to prevent pollution from former operations, such as plugging abandoned wells or closing pits; and impose substantial liabilities for unauthorized pollution resulting from our operations. The EPA and analogous state agencies may delay or refuse the issuance of required permits or otherwise include onerous or limiting permit conditions that may have a significant adverse impact on our ability to conduct operations. The regulatory burden on the oil and gas industry increases the cost of doing business and consequently affects its profitability.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly material handling, storage, transport, disposal or cleanup requirements could materially and adversely affect our operations and financial position, as well as those of the oil and gas industry in general. While we believe that we are in compliance, in all material respects, with current applicable environmental laws and regulations and have not experienced any material adverse effect from compliance with these environmental requirements, there is no assurance that this trend will continue in the future.

The environmental laws and regulations which have the most significant impact on the oil and gas exploration and production industry are as follows:

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA" or "Superfund"), and comparable state laws impose strict joint and several liability, without regard to fault or the legality of conduct, on classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site where a release occurred and anyone who disposed or arranged for the disposal of the hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. It is not uncommon 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. In the course of our ordinary operations, we may generate material that may be regulated as "hazardous substances." Consequently, we may be jointly and severally liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these materials have been disposed or released.

We currently own or lease, and in the past have owned or leased, properties that for many years have been used for the exploration and production of oil and gas. Although we and our predecessors have used operating and disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on, under or from the properties owned or leased by us or on, under or from other locations where such substances have been taken for recycling or disposal. In addition, many of these owned and leased properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons was not under our control. Similarly, the disposal facilities where discarded materials are sent are also often operated by third parties whose waste treatment and disposal practices may not be adequate. While we only use what we consider to be reputable disposal facilities, we might not know of a potential problem if the disposal occurred before we acquired the property or business, and if the problem itself is not discovered until years later. Our properties, adjacent affected properties, the offsite disposal facilities, and the substances disposed or released on them may be subject to CERCLA and analogous state laws. Under these laws, we could be required:

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- to remove or remediate previously disposed materials, including materials disposed or released by prior owners or operators or other third parties;
- to clean up contaminated property, including contaminated groundwater;
- to perform remedial operations to prevent future contamination, including the plugging and abandonment of wells drilled and left inactive by prior owners and operators; or
- to pay some or all of the costs of any such action.

At this time, we do not believe that we are a potentially responsible party with respect to any Superfund site and we have not been notified of any claim, liability or damages under CERCLA.

Oil Pollution Act. The Oil Pollution Act of 1990 ("OPA") and regulations issued under OPA impose strict, joint and several liability on "responsible parties" for removal costs and damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility and the lessee, permittee or holder of a right of use and easement of the area in which an offshore facility is located. OPA establishes a liability limit for onshore facilities of $350.0 million per spill, while the liability limit for offshore facilities is the payment of all removal costs plus $75.0 million per spill damages. These limits do not apply if the spill is caused by a responsible party's gross negligence or willful misconduct; the spill resulted from a responsible party's violation of a federal safety, construction or operating regulation; a responsible party fails to report a spill or to cooperate fully in a cleanup; or a responsible party fails to comply with an order issued under the authority of the Intervention on the High Seas Act. OPA also requires the lessee or permittee of the offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility in the amount of $35.0 million to cover liabilities related to an oil spill for which such responsible party is statutorily responsible. The President may increase the amount of financial responsibility required under OPA by up to $150.0 million, depending on the risk represented by the quantity or quality of oil that is handled by the facility. Any failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to administrative penalties up to $25,000 per day per violation. We believe we are in compliance with all applicable OPA financial responsibility obligations. Moreover, we are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA's financial responsibility and other operating requirements will not have a material adverse effect on us.

Resource Conservation Recovery Act. The Resource Conservation and Recovery Act ("RCRA"), and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own more stringent requirements. We generate solid and hazardous wastes that are subject to RCRA and comparable state laws. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of crude oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous waste in the future. In September 2010, the Natural Resources Defense Council filed a petition with the EPA, requesting them to reconsider the RCRA exemption for exploration, production and development wastes but, to date, the agency has not taken any action on the petition. The EPA has not formally responded to this petition yet. Any such change in the current RCRA exemption and comparable state laws could result in an increase in the costs to manage and dispose of wastes. Additionally, these exploration and production wastes may be regulated by state agencies as solid waste. Also, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes and waste compressor oils may be regulated as hazardous waste. Although we do not believe the current costs of managing our materials constituting wastes (as they are presently classified) to be significant, any repeal or modification of the oil and gas exploration and production exemption by administrative, legislative or judicial process, or modification of similar exemptions in analogous state statutes would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses.

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Clean Water Act. The Federal Water Pollution Control Act, or the Clean Water Act, as amended ("CWA"), and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into state waters or other waters of the United States. The discharge of pollutants
into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities.

The EPA had regulations under the authority of CWA that required certain oil and gas exploration and production projects to obtain permits for construction projects with storm water discharges. However, the Energy Policy Act of 2005 nullified most of the EPA regulations that required storm water permitting of oil and gas construction projects. There are still some state and federal rules that regulate the discharge of storm water from some oil and gas construction projects. Costs may be associated with the treatment of wastewater and/or developing and implementing storm water pollution prevention plans. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of CWA and analogous state laws and regulations. In Section 40 CFR 112 of the regulations, the EPA promulgated the Spill Prevention, Control and Countermeasure ("SPCC") regulations, which require certain oil containing facilities to prepare plans and meet construction and operating standards.

Air Emissions. The Federal Clean Air Act, as amended (the "CAA"), and comparable state laws regulate emissions of various air pollutants from various industrial sources through air emissions permitting programs and also impose other monitoring and reporting requirements. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining pre-construction and operating permits and approvals for air emissions. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. For example, in 2012, the EPA finalized rules establishing new air emission controls for oil and natural gas production operations. Specifically, the EPA's rule includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. Among other things, these standards require the application of reduced emission completion techniques associated with the completion of newly drilled and fractured wells in addition to existing wells that are refractured. The rules also establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. These rules could require a number of modifications to operations at certain of our oil and gas properties including the installation of new equipment. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, which may adversely impact our business. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations.

Hydraulic Fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight rock formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing has been utilized to complete wells in our most active areas located in the states of Colorado, Michigan, Montana, North Dakota and Texas, and we expect it will also be used in the future. Should our exploration and production activities expand to other states, it is likely that we will utilize hydraulic fracturing to complete or recomplete wells in those areas. The process is typically regulated by state oil and gas commissions. However, the EPA recently issued guidance, which was published in the Federal Register on February 12, 2014, for permitting authorities and the industry regarding the process for obtaining a permit for hydraulic fracturing involving diesel.

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At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities on drinking water resources. The EPA published a progress report of the study in December 2012 and expects to release a draft final report for public comment and peer review in 2014. Moreover, the EPA announced in October 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards for coalbed methane in 2013 and shale gas in 2014 that such wastewater must meet before being transported to a treatment plant. Other federal agencies are also examining hydraulic fracturing, including the U.S. Department of Energy, the U.S. Government Accountability Office and the White House Council for Environmental Quality. The U.S. Department of the Interior released a draft proposed rule in May 2012 governing hydraulic fracturing on federal and Indian oil and natural gas leases to require disclosure of information regarding the chemicals used in hydraulic fracturing, advance approval for well-stimulation activities, mechanical integrity testing of casing and monitoring of well-stimulation operations, and on May 24, 2013 the Federal Bureau of Land Management issued a revised draft of the proposed rule. On November 20, 2013, the U.S. House of Representatives passed the Protecting States' Rights to Promote American Energy Security Act, which would ban the U.S. Department of the Interior from regulating hydraulic fracturing if enacted into law. In addition, legislation has been introduced in Congress from time to time to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Also, some states have adopted, and other states are considering adopting, regulations that could restrict or impose additional requirements on activities relating to hydraulic fracturing in certain circumstances. For example, on June 17, 2011, Texas enacted a law that requires the disclosure of information regarding the substances used in the hydraulic fracturing process to the Railroad Commission of Texas (the entity that regulates oil and natural gas production in Texas) and the public. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. Disclosure of chemicals used in the fracturing process could make it easier for third parties opposing hydraulic fracturing to pursue legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect human health or the environment, including groundwater. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays, litigation risk and potential increases in costs. Further, local governments may seek to adopt, and some have adopted, ordinances within their jurisdictions restricting the use of or regulating the time, place and manner of drilling or hydraulic fracturing. No assurance can be given as to whether or not similar measures might be considered or implemented in the jurisdictions in which our properties are located. If new laws, regulations or ordinances that significantly restrict or otherwise impact hydraulic fracturing are passed by Congress or adopted in the states or local municipalities where our properties are located, such legal requirements could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby could affect the determination of whether a well is commercially viable. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercially paying quantities.

Global Warming and Climate Change. On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHG") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. Based on these findings, the EPA has begun adopting and implementing regulations that restrict emissions of GHG under existing provisions of the CAA, including one rule that limits emissions of GHG from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger the CAA construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards took effect on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first becoming subject to permitting. Further, facilities required to obtain PSD permits for their GHG emissions are required to reduce those emissions consistent with guidance for determining "best available control technology" standards for GHG, which guidance was published by the EPA in November 2010. Also in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis with reporting beginning in 2012 for emissions occurring in 2011. We believe that we are in compliance with all substantial applicable emissions requirements, and we are preparing to comply with future requirements.

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In addition, both houses of Congress have considered legislation to reduce emissions of GHG, and many states have already taken legal measures to reduce emissions of GHG, primarily through the development of GHG inventories, greenhouse gas permitting and/or regional GHG "cap and trade" programs. Most of these "cap and trade" programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. In the absence of new legislation, the EPA is issuing new regulations that limit emissions of GHG associated with our operations, which will require us to incur costs to inventory and reduce emissions of GHG associated with our operations and which could adversely affect demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our assets and operations.

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operations frequently require licenses, permits and/or other governmental approvals. Several federal statutes, including the Outer Continental Shelf Lands Act ("OCSLA"), the National Environmental Policy Act ("NEPA") and the Coastal Zone Management Act ("CZMA") require federal agencies to evaluate environmental issues in connection with granting such approvals and/or taking other major agency actions. OCSLA, for instance, requires the U.S. Department of Interior to evaluate whether certain proposed activities would cause serious harm or damage to the marine, coastal or human environment. Similarly, NEPA requires the Department of Interior and other federal agencies to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency would have to prepare an environmental assessment and potentially an environmental impact statement. The CZMA, on the other hand, aids states in developing a coastal management program to protect the coastal environment from growing demands associated with various uses, including offshore oil and gas development. In obtaining various approvals from the Department of Interior, we must certify that we will conduct our activities in a manner consistent with all applicable regulations.

Employees

As of December 31, 2013, we had 958 full-time employees, including 39 senior level geoscientists and 73 petroleum engineers. Our employees are not represented by any labor unions. We consider our relations with our employees to be satisfactory and have never experienced a work stoppage or strike.

Available Information

We maintain a website at the address www.whiting.com. We are not including the information contained on our website as part of, or incorporating it by reference into, this report. We make available free of charge (other than an investor's own Internet access charges) through our website our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, including exhibits and amendments to these reports, as soon as reasonably practicable after we electronically file such material with, or furnish such material to, the Securities and Exchange Commission.

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Item 1A. Risk Factors

Each of the risks described below should be carefully considered, together with all of the other information contained in this Annual Report on Form 10-K, before making an investment decision with respect to our securities. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially and adversely affected, and you may lose all or part of your investment.

Oil and natural gas prices are very volatile. An extended period of low oil and natural gas prices may adversely affect our business, financial condition, results of operations or cash flows.

The oil and gas markets are very volatile, and we cannot predict future oil and natural gas prices. The price we receive for our oil, NGL and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. The prices we receive for our production depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in regional, domestic and global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and natural gas;
- political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activity, such as recent conflicts in the Middle East;
- the level of global oil and natural gas exploration and production activity;
- the effects of global credit, financial and economic issues;
- the level of global oil and natural gas inventories;
- developments of United States energy infrastructure, such as the approval to proceed with the Keystone XL pipeline from Hardesty, Alberta to Cushing, Oklahoma and the development of liquefied natural gas exporting facilities and the perceived timing thereof;
- weather conditions;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and natural gas in captive market areas;
- the price and availability of alternative fuels; and
- acts of force majeure.

Moreover, government regulations, such as regulation of oil and natural gas gathering and transportation, can adversely affect commodity prices in the long term.

Lower oil, NGL and natural gas prices may not only decrease our revenues on a per unit basis but also may ultimately reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our reserve quantities. A substantial or extended decline in oil, NGL or natural gas prices may result in impairments of our proved oil and gas properties and may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. To the extent commodity prices received from production are insufficient to fund planned capital expenditures, we will be required to reduce spending or borrow any such shortfall. Lower oil, NGL and natural gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement.

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

Our future success will depend on the success of our exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Please read "— Reserve estimates depend on many assumptions that may turn out to be inaccurate..." later in these Risk Factors for a discussion of the uncertainty involved in these processes. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- delays or limits on the issuance of drilling permits on our federal leases, including as a result of government shutdowns;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs, completion services and CO2;
- equipment failures or accidents;
- adverse weather conditions, such as freezing temperatures, hurricanes and storms;
- reductions in oil, NGL and natural gas prices;
- pipeline takeaway and refining and processing capacity; and
- title problems.

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight rock formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing has been utilized to complete wells in our most active areas located in the states of Colorado, Michigan, Montana, North Dakota and Texas, and we expect it will also be used in the future. Should our exploration and production activities expand to other states, it is likely that we will utilize hydraulic fracturing to complete or recomplete wells in those areas. The process is typically regulated by state oil and gas commissions. However, the U.S. Environmental Protection Agency (the "EPA") recently issued guidance, which was published in the Federal Register on February 12, 2014, for permitting authorities and the industry regarding the process for obtaining a permit for hydraulic fracturing involving diesel.

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At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities on drinking water resources. The EPA published a progress report of the study in December 2012 and expects to release a draft final report for public comment and peer review in 2014. Moreover, the EPA announced in October 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards for coalbed methane in 2013 and shale gas in 2014 that such wastewater must meet before being transported to a treatment plant. Other federal agencies are also examining hydraulic fracturing, including the U.S. Department of Energy, the U.S. Government Accountability Office and the White House Council for Environmental Quality. The U.S. Department of the Interior released a draft proposed rule in May 2012 governing hydraulic fracturing on federal and Indian oil and natural gas leases to require disclosure of information regarding the chemicals used in hydraulic fracturing, advance approval for well-stimulation activities, mechanical integrity testing of casing and monitoring of well-stimulation operations, and on May 24, 2013 the Federal Bureau of Land Management issued a revised draft of the proposed rule. On November 20, 2013, the U.S. House of Representatives passed the Protecting States' Rights to Promote American Energy Security Act, which would ban the U.S. Department of the Interior from regulating hydraulic fracturing if enacted into law. In addition, legislation has been introduced in Congress from time to time to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Also, some states have adopted, and other states are considering adopting, regulations that could restrict or impose additional requirements on activities relating to hydraulic fracturing in certain circumstances. For example, on June 17, 2011, Texas enacted a law that requires the disclosure of information regarding the substances used in the hydraulic fracturing process to the Railroad Commission of Texas (the entity that regulates oil and natural gas production in Texas) and the public. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. Disclosure of chemicals used in the fracturing process could make it easier for third parties opposing hydraulic fracturing to pursue legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect human health or the environment, including groundwater. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays, litigation risk and potential increases in costs. Further, local governments may seek to adopt, and some have adopted, ordinances within their jurisdictions restricting the use of or regulating the time, place and manner of drilling or hydraulic fracturing. No assurance can be given as to whether or not similar measures might be considered or implemented in the jurisdictions in which our properties are located. If new laws, regulations or ordinances that significantly restrict or otherwise impact hydraulic fracturing are passed by Congress or adopted in the states or local municipalities where our properties are located, such legal requirements could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby could affect the determination of whether a well is commercially viable. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercially paying quantities.

Refer to "Hydraulic Fracturing" in Item 2 of this Annual Report on Form 10-K for more information on hydraulic fracturing.

Our use of enhanced recovery methods creates uncertainties that could adversely affect our results of operations and financial condition.

One of our business strategies is to commercially develop oil reservoirs using enhanced recovery technologies. For example, we inject water and CO_2 into formations on some of our properties to increase the production of oil and natural gas. The additional production and reserves attributable to the use of these enhanced recovery methods are inherently difficult to predict. If our enhanced recovery programs do not allow for the extraction of oil and gas in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected. Additionally, our ability to utilize CO_2 injection as an enhanced recovery technique is subject to our ability to obtain sufficient quantities of CO_2. Under our CO_2 contracts, if the supplier suffers an inability to deliver its contractually required quantities of CO_2 to us and other parties with whom it has CO_2 contracts, then the supplier may reduce the amount of CO_2 on a pro rata basis it provides to us and such other parties. If this occurs or if we are otherwise limited in the quantities of CO_2 available to us, we may not have sufficient CO_2 to produce oil and natural gas in the manner or to the extent that we anticipate, and our future oil and gas production volumes could be negatively impacted. These contracts are also structured as "take-or-pay" arrangements, which require us to continue to make payments even if we decide to terminate or reduce our use of CO_2 as part of our enhanced recovery techniques.

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The development of the proved undeveloped reserves in the North Ward Estes field may take longer and may require higher levels of capital expenditures than we currently anticipate.

As of December 31, 2013, proved undeveloped reserves comprised 39% of the North Ward Estes field's total estimated proved reserves. To fully develop these reserves, we expect to incur future development costs of $684.2 million at the North Ward Estes field as of December 31, 2013. This field encompasses 20% of our total estimated future development costs related to proved undeveloped reserves. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. In addition, the development of these reserves will require the use of enhanced recovery techniques, including water flood and CO2 injection installations, the success of which is less predictable than traditional development techniques.

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

We describe some of our current prospects and our plans to explore those prospects in this Annual Report on Form 10-K. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of oil or gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or gas will be present or, if present, whether oil or gas will be present in commercial quantities. In addition, because of the wide variance that results from different equipment used to test the wells, initial flow rates may not be indicative of sufficient oil or gas quantities in a particular field. The analogies we draw from available data from other wells, from more fully explored prospects, or from producing fields may not be applicable to our drilling prospects. We may terminate our drilling program for a prospect if results do not merit further investment.

If oil, NGL and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and gas properties.

Accounting rules require that we periodically review the carrying value of our producing oil and gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews (which may include depressed oil, NGL and natural gas prices, and the continuing evaluation of development plans, production data, economics and other factors) we may be required to write down the carrying value of our oil and gas properties. For example, we recorded a $220.8 million impairment write-down during 2013 for the partial impairment of producing properties, primarily natural gas, in Michigan, Utah and Wyoming. A write-down constitutes a non-cash charge to earnings. We may incur additional impairment charges in the future, which could have a material adverse effect on our results of operations in the period recognized.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves referred to in this Annual Report on Form 10-K.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as the following:

- historical production from the area compared with production rates from other producing areas;
- the assumed effect of governmental regulation; and
- assumptions about future prices of oil, NGLs and natural gas including differentials, production and development costs, gathering and transportation costs, severance and excise taxes, capital expenditures and availability of funds.

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Therefore, estimates of oil and natural gas reserves are inherently imprecise. Actual future production; oil, NGL and natural gas prices; revenues; taxes; exploration and development expenditures; operating expenses; and quantities of recoverable oil and natural gas reserves will most likely vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves referred to in this Annual Report on Form 10-K. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our proved reserves, as referred to in this report, is the current market value of our estimated proved oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on 12-month average prices and current costs as of the date of the estimate. Actual future prices and costs may differ materially from those used in the estimate. If natural gas prices decline by $0.10 per Mcf, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2013 would have decreased from $6,593.9 million to $6,583.2 million. If oil prices decline by $1.00 per Bbl, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2013 would have decreased from $6,593.9 million to $6,483.8 million.

Risks associated with the production, gathering, transportation and sale of oil, NGLs and natural gas could adversely affect net income and cash flows.

Our net income and cash flows will depend upon, among other things, oil, NGL and natural gas production and the prices and costs incurred to develop and produce oil and natural gas reserves. Drilling, production or transportation accidents that temporarily or permanently halt the production and sale of oil, NGLs and natural gas will decrease revenues and increase expenditures. For example, accidents may occur that result in personal injuries, property damage, damage to productive formations or equipment and environmental damages. Any costs incurred in connection with any such accidents that are not insured against will have the effect of reducing net income. Also, we do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations. Please read "— Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing..." above in these Risk Factors for a discussion of the uncertainty involved in the regulation of hydraulic fracturing. In addition, curtailments or damage to pipelines used to transport oil, NGLs and natural gas production to markets for sale could decrease revenues or increase transportation expenses. Any such curtailments or damage to the gathering systems could also require finding alternative means to transport the oil, NGLs and natural gas production, which alternative means could result in additional costs that will have the effect of increasing transportation expenses.

Also, there have been recent accidents involving rail cars carrying Bakken formation crude oil, which resulted in the U.S. Department of Transportation (the "DOT") issuing an emergency order on February 25, 2014 that requires rail shippers to test the makeup of such crude oil before transporting it. This move follows the safety alert the DOT issued in January 2014 that Bakken formation crude oil is more flammable than other types of crude oil. An accident involving rail cars could result in significant personal injuries and property and environmental damage. Additionally, added regulations in response to such accidents could result in additional costs that could increase transportation expenses.

In addition, drilling, production and transportation of hydrocarbons bear the inherent risk of loss of containment. Potential consequences include loss of reserves, loss of production, loss of economic value associated with the affected wellbore, contamination of soil, ground water and surface water, as well as potential fines, penalties or damages associated with any of the foregoing consequences.

Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, results of operations, cash flows and business prospects.

As of December 31, 2013, we had no borrowings and $3.0 million in letters of credit outstanding under Whiting Oil and Gas Corporation’s (“Whiting Oil and Gas”) credit facility with $1,197.0 million of available borrowing capacity, as well as $2,300.0 million of senior notes outstanding and $350.0 million of senior subordinated notes outstanding. We are allowed to incur additional indebtedness, provided that we meet certain requirements in the indentures governing our senior notes and our senior subordinated notes and Whiting Oil and Gas’ credit agreement.

Our level of indebtedness and the covenants contained in the agreements governing our debt could have important consequences for our operations, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- placing us at a competitive disadvantage relative to other less leveraged competitors; and
- making us vulnerable to increases in interest rates, because debt under Whiting Oil and Gas' credit agreement is subject to certain rate variability.

We may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the acceleration of our repayment of outstanding debt. In addition, if we are in default under the agreements governing our indebtedness, we would not be able to pay dividends on our capital stock. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions. Moreover, the borrowing base limitation on Whiting Oil and Gas' credit agreement is periodically redetermined based on an evaluation of our oil and gas reserves. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of our debt outstanding under the credit agreement.

We may not have sufficient funds to make such repayments. If we are unable to repay our debt out of cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We may not be able to generate sufficient cash flow to pay the interest on our debt or future borrowings, and equity financings or proceeds from the sale of assets may not be available to pay or refinance such debt. The terms of our debt, including Whiting Oil and Gas' credit agreement, may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We may not be able to successfully complete any such offering, refinancing or sale of assets.

The instruments governing our indebtedness contain various covenants limiting the discretion of our management in operating our business.

The indentures governing our senior notes and our senior subordinated notes and Whiting Oil and Gas' credit agreement contain various restrictive covenants that may limit our management's discretion in certain respects. In particular, these agreements will limit our and our subsidiaries' ability to, among other things:

- pay dividends on, redeem or repurchase our capital stock or redeem or repurchase our senior or subordinated debt;
- make loans to others;
- make investments;
- incur additional indebtedness or issue preferred stock;
- create certain liens;
- sell assets;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets and those of our restricted subsidiaries taken as a whole;
- engage in transactions with affiliates;
- enter into hedging contracts;
- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

In addition, Whiting Oil and Gas' credit agreement requires us, as of the last day of any quarter, (i) to not exceed a total debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 4.0 to 1.0 and (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0. Also, the indentures under which we issued our senior notes and our senior subordinated notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If we were in violation of these covenants, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas' credit agreement. A substantial or extended decline in oil or natural gas prices may adversely affect our ability to comply with these covenants.

If we fail to comply with the restrictions in the indentures governing our senior notes and our senior subordinated notes or Whiting Oil and Gas' credit agreement or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make further funds available to us. Furthermore, if we are in default under the agreements governing our indebtedness, we will not be able to pay dividends on our capital stock.

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

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of oil and natural gas reserves. To date, we have financed capital expenditures through a combination of equity and debt issuances, bank borrowings, internally generated cash flows and oil and gas property divestments. We intend to finance future capital expenditures with cash flow from operations, cash on hand and existing financing arrangements. Our cash flow from operations and access to capital is subject to a number of variables, including:

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

If our revenues or the borrowing base under our credit agreement decreases as a result of lower oil and natural gas prices, operating difficulties, declines in reserves, or for any other reason, then we may have limited ability to obtain the capital necessary to sustain our operations at current levels.

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We may, from time to time, need to seek additional financing. There can be no assurance as to the availability or terms of any additional financing. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves.

Our acquisition activities may not be successful.

As part of our growth strategy, we have made and may continue to make acquisitions of businesses and properties. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable, and acquisitions pose substantial risks to our business, financial condition and results of operations. In pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources to acquire attractive companies and properties. The following are some of the risks associated with acquisitions, including any completed or future acquisitions:

- some of the acquired businesses or properties may not produce revenues, reserves, earnings or cash flow at anticipated levels;
- we may assume liabilities that were not disclosed to us or that exceed our estimates;
- we may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems;
- acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures; and
- we may issue additional equity or debt securities in order to fund future acquisitions.

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

In order to finance acquisitions of additional producing or undeveloped properties, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for additional future acquisitions or other transactions or to obtain external funding on terms acceptable to us.

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

The demand for qualified and experienced field personnel to conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling rigs and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. Additionally, our operations in some instances require supply materials for production, such as CO_2, which could become subject to shortage and increasing costs. Shortages of field personnel, drilling rigs, equipment, supplies or personnel or price increases could delay or adversely affect our exploration and development operations, which could have a material adverse effect on our business, financial condition, results of operations or cash flows, or restrict operations.

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

We have specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of December 31, 2013, we had identified a drilling inventory of over 3,200 gross drilling locations. These scheduled drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability of capital, costs of oil field goods and services, drilling results, our ability to extend drilling acreage leases beyond expiration, regulatory approvals and other factors. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could in turn adversely affect our business.

We have been an early entrant into new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage may decline, and we may incur impairment charges if drilling results are unsuccessful.

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. Therefore, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful. Furthermore, if drilling results are unsuccessful, we may be required to write down the carrying value of our undeveloped acreage in new or emerging plays. For example, during the fourth quarter of 2013, we recorded a $13.6 million non-cash charge for the impairment of unproved properties in our Flat Rock field in Utah. We may also incur such impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken. Additionally, our rights to develop a portion of our undeveloped acreage may expire if not successfully developed or renewed. See “Acreage” in Item 2 of this Annual Report on Form 10-K for more information relating to the expiration of our rights to develop undeveloped acreage.

Properties that we acquire may not produce as projected, and we may be unable to identify liabilities associated with the properties or obtain indemnities from sellers for liabilities they may have created.

Our business strategy includes a continuing acquisition program. From 2004 through 2013, we completed 17 separate significant acquisitions of producing properties with a combined purchase price of $2,160.3 million for estimated proved reserves as of the effective dates of the acquisitions of 248.0 MMBOE. The successful acquisition of producing properties requires assessment of many factors, which are inherently inexact and may be inaccurate, including the following:

- the amount of recoverable reserves;
- future oil and natural gas prices;
- estimates of operating costs;
- estimates of future development costs;
- timing of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- the assumption of unknown potential environmental and other liabilities, losses or costs, including for example, historical spills or releases for which we are not indemnified or for which our indemnity is inadequate.

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Our assessment will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well, platform, facility or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination, when they are made. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

We may not be able to replace the reserves on properties we divest, and the agreements pursuant to which assets we divest may contain continuing indemnification obligations.

Part of our business strategy includes selling properties when we believe that the sales price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own. Unless we conduct successful exploration, development and production activities or acquire properties containing proved reserves, divestitures of our properties will reduce our proved reserves and potentially our production. We may not be able to develop, find or acquire additional reserves sufficient to replace such reserves and production from any of the properties we sell. Additionally, agreements pursuant to which we sell properties may include terms that survive closing of the sale, including indemnification provisions, which could obligate us to substantial liabilities.

Our use of oil and natural gas price hedging contracts involves credit risk and may limit higher revenues in the future in connection with commodity price increases and may result in significant fluctuations in our net income.

We enter into hedging transactions of our oil and natural gas production revenues to reduce our exposure to fluctuations in the price of oil and natural gas. Our hedging transactions to date have consisted of financially settled crude oil and natural gas options contracts, primarily costless collars, placed with major financial institutions. As of February 6, 2014, we had contracts, which include our 10% share of the Whiting USA Trust II hedges, covering the sale of between 1,204,250 and 1,284,250 barrels of oil per month for all of 2014. All of our oil hedges will expire by December 2014. See “Quantitative and Qualitative Disclosures about Market Risk” in Item 7A of this Annual Report on Form 10-K for pricing information and a more detailed discussion of our hedging transactions.

We may in the future enter into these and other types of hedging arrangements to reduce our exposure to fluctuations in the market prices of oil and natural gas, or alternatively, we may decide to unwind or restructure the hedging arrangements we previously entered into. Hedging transactions expose us to risk of financial loss in some circumstances, including if production is less than expected, the other party to the contract defaults on its obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. Hedging transactions may limit the benefit we may otherwise receive from increases in the price for oil and natural gas. Furthermore, if we do not engage in hedging transactions or unwind hedging transactions we previously entered into, then we may be more adversely affected by declines in oil and natural gas prices than our competitors who engage in hedging transactions. Additionally, hedging transactions may expose us to cash margin requirements.

We recognize all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive income. Consequently, we may experience significant net losses, on a non-cash basis, due to changes in the value of our hedges as a result of commodity price volatility.

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Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas, drilling and other oil and gas activities can only be conducted during the spring and summer months. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. Resulting shortages or high costs could delay our operations, cause temporary declines in our oil and gas production and materially increase our operating and capital costs.

An increase in the differential or decrease in the premium between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

The prices that we receive for our oil and natural gas production generally trade at a discount, but sometimes at a premium, to the relevant benchmark prices such as NYMEX. A negative difference between the benchmark price and the price received is called a differential and a positive difference is called a premium. The differential and premium may vary significantly due to market conditions, the quality and location of production and other risk factors. We cannot accurately predict oil and natural gas differentials and premiums. Increases in the differential and decreases in the premium between the benchmark price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and gas operations.

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

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

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, then it could adversely affect us.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues and increase capital expenditures.

We operate 77% of our net productive oil and natural gas wells, which represents 86% of our proved developed producing reserves as of December 31, 2013. If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of our properties. The failure of an operator of our wells to adequately perform operations or an operator’s breach of the applicable agreements could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator’s decisions with respect to the timing and amount of capital expenditures, the period of time over which the operator seeks to generate a return on capital expenditures, inclusion of other participants in drilling wells, and the use of technology, as well as the operator’s expertise and financial resources and the operator’s relative interest in the field. Operators may also opt to decrease operational activities following a significant decline in oil or natural gas prices. Because we do not have a majority interest in most wells we do not operate, we may not be in a position to remove the operator in the event of poor performance. Accordingly, while we use commercially reasonable efforts to cause the operator to act as a reasonably prudent operator, we are limited in our ability to do so.

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Our use of 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies do, and we could incur losses as a result of such expenditures. Thus, some of our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline. We often gather 3-D seismic data over large areas. Our interpretation of seismic data delineates for us those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data, and in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, it would result in our having made substantial expenditures to acquire and analyze 3-D seismic data without having an opportunity to attempt to benefit from those expenditures.

Market conditions or operational impediments may hinder our access to oil and gas markets or delay our production.

In connection with our continued development of oil and gas properties, we may be disproportionately exposed to the impact of delays or interruptions of production from wells in these properties, caused by transportation capacity constraints, curtailment of production or the interruption of transporting oil and gas volumes produced. In addition, market conditions or a lack of satisfactory oil and gas transportation arrangements may hinder our access to oil and gas markets or delay our production. The availability of a ready market for our oil, NGL and natural gas production depends on a number of factors, including the demand for and supply of oil, NGLs and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends substantially on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third-parties. Additionally, entering into arrangements for these services exposes us to the risk that third parties will default on their obligations under such arrangements. Our failure to obtain such services on acceptable terms or the default by a third party on their obligation to provide such services could materially harm our business. We may be required to shut in wells for a lack of a market or because access to gas pipelines, gathering systems or processing facilities may be limited or unavailable. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver the production to market.

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

Exploration, development, production and sale of oil and natural gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

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

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Under these laws, we could be liable for personal injuries, property damage and other damages. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws could change in ways that could substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our financial condition and results of operations.

Our operations may incur substantial costs and liabilities to comply with environmental laws and regulations.

Our oil and gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences; restrict the types, quantities and concentration of materials that can be released into the environment in connection with drilling and production activities; limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and impose substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, incurrence of investigatory or remedial obligations, or the imposition of injunctive relief. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or if our operations were standard in the industry at the time they were performed. Private parties, including the surface owners of properties upon which we drill, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. We may not be able to recover some or any of these costs from insurance. Moreover, federal law and some state laws allow the government to place a lien on real property for costs incurred by the government to address contamination on the property.

Changes in environmental laws and regulations occur frequently and may have a materially adverse impact on our business. For example, in 2012, the EPA published final rules under the Federal Clean Air Act that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants. With regards to production activities, these rules require, among other things, the reduction of volatile organic compound emissions from certain fractured and refractured gas wells for which well completion operations are conducted and, in particular, requiring some of these wells to use reduced emission completions, also known as “green completions,” after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, pneumatic controllers and storage vessels. Any increased governmental regulation or suspension of oil and natural gas exploration or production activities that arises out of these incidents could result in higher operating costs, which could in turn adversely affect our operating results. Also, for instance, any changes in laws or regulations that result in more stringent or costly material handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position or financial condition as well as those of the oil and gas industry in general.

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

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases (“GHG”) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth’s atmosphere and other climate changes. Based on these findings, the EPA has begun adopting and implementing regulations that restrict emissions of GHG under existing provisions of the Federal Clean Air Act (the “CAA”), including one rule that limits emissions of GHG from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle

GHG emission standards trigger the CAA construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards took effect on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Further, facilities required to obtain PSD permits for their GHG emissions are required to reduce those emissions consistent with guidance for determining "best available control technology" standards for GHG, which guidance was published by the EPA in November 2010. Also in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis with reporting beginning in 2012 for emissions occurring in 2011.

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In addition, both houses of Congress have actively considered legislation to reduce emissions of GHG, and many states have already taken legal measures to reduce emissions of GHG, primarily through the development of GHG inventories, greenhouse gas permitting and/or regional GHG "cap and trade" programs. Most of these "cap and trade" programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. In the absence of new legislation, the EPA is issuing new regulations that limit emissions of GHG associated with our operations which will require us to incur costs to inventory and reduce emissions of GHG associated with our operations and which could adversely affect demand for the oil, NGLs and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our assets and operations.

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

Unless we conduct successful exploration, development and production activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing and producing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production.

The loss of senior management or technical personnel could adversely affect us.

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including James J. Volker, Chairman and Chief Executive Officer; James T. Brown, President and Chief Operating Officer; Mark R. Williams, Senior Vice President, Exploration and Development; Steven A. Kranker, Vice President, Reservoir Engineering/Acquisitions; Rick A. Ross, Vice President, Operations; David M. Seery, Vice President, Land; Michael J. Stevens, Vice President and Chief Financial Officer; or Peter W. Hagist, Vice President, Permian Operations, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

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

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

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

In April 2013, President Obama's Administration released its proposed federal budget for fiscal year 2014 that would, if enacted into law, 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. Such changes include, but are not limited to:

- the repeal of the percentage depletion allowance for oil and gas properties;
- the elimination of current deductions for intangible drilling and development costs;
- the elimination of the deduction for U.S. oil and gas production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures.

It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. The passage of any legislation containing these or similar changes in U.S. federal income tax law could eliminate or defer certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such changes could negatively affect our financial condition and results of operations.

In connection with the passage of the Dodd-Frank Wall Street Reform and Consumer Protection Act, new regulations forthcoming in this area may result in increased costs and cash collateral requirements for the types of oil and gas derivative instruments we use to manage our risks related to oil and gas commodity price volatility.

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was enacted into law. This financial reform legislation includes provisions that require over-the-counter derivative transactions to be executed through an exchange or centrally cleared. In addition, the legislation provides an exemption from mandatory clearing requirements based on regulations to be developed by the Commodity Futures Trading Commission (the "CFTC") and the SEC for transactions by non-financial institutions to hedge or mitigate commercial risk. At the same time, the legislation includes provisions under which the CFTC may impose collateral requirements for transactions, including those that are used to hedge commercial risk. However, during drafting of the legislation, members of Congress adopted report language and issued a public letter stating that it was not their intention to impose margin and collateral requirements on counterparties that utilize transactions to hedge commercial risk. Final rules on major provisions in the legislation, like new margin requirements, will be established through rulemakings and will not take effect until 12 months after the date of enactment. Although we cannot predict the ultimate outcome of these rulemakings, new regulations in this area may result in increased costs and cash collateral requirements for the types of oil and gas derivative instruments we use to hedge and to otherwise manage our financial risks related to volatility in oil and gas commodity prices.

Item 1B. Unresolved Staff Comments

None.

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Item 2. Properties

Summary of Oil and Gas Properties and Projects

Rocky Mountains Region

Our Rocky Mountains operations include assets in the states of North Dakota, Colorado, Montana, Wyoming, Utah and California. As of December 31, 2013, our estimated proved reserves in the Rocky Mountains region were 297.0 MMBOE (80% oil), which represented 68% of our total estimated proved reserves and contributed 84.7 MBOE/d of average daily production in the fourth quarter of 2013.

Sanish and Parshall Fields. Our Sanish and Parshall fields in Mountrail County, North Dakota target the Bakken and Three Forks formations and encompass approximately 174,700 gross (82,400 net) developed and undeveloped acres. Net production in the Sanish and Parshall fields averaged 40.4 MBOE/d for the fourth quarter of 2013, representing a 10% increase from 36.8 MBOE/d in the third quarter of 2013. As of December 31, 2013, we had four drilling rigs active in the Sanish field. We also initiated three high density pilot programs in the Sanish field and participated in several infill wells in the Parshall field during 2013. We recently completed two infill wells using our new completion design and are encouraged by the initial results.

In order to process the produced gas stream from the Sanish wells, we constructed and brought on-line the Robinson Lake gas plant. The plant has a current processing capacity of 90 MMcf/d and fractionation equipment that allows us to convert NGLs into propane and butane, which end products can then be sold locally for higher realized prices. We currently have projects underway to expand the inlet compression and processing capability at this plant to 110 MMcf/d.

Lewis & Clark/Pronghorn Fields. Our Lewis & Clark/Pronghorn fields are located primarily in the Stark and Billings counties of North Dakota and run along the Bakken shale pinch-out in the southern Williston Basin. In this area, the Upper Bakken shale is thermally mature, moderately over-pressured, and we believe that it has charged reservoir zones within the immediately underlying Pronghorn Sand and Three Forks formations (Middle Bakken and Lower Bakken Shale is absent). As of December 31, 2013, the Lewis & Clark/Pronghorn fields encompassed approximately 392,500 gross (263,400 net) developed and undeveloped acres. Net production in the Lewis & Clark/Pronghorn fields averaged 15.1 MBOE/d in the fourth quarter of 2013, representing a 6% increase from 14.2 MBOE/d in the third quarter of 2013. As of December 31, 2013, we had four drilling rigs operating in the Pronghorn field, all of which are utilizing drilling pads, with two or three wells from each pad. Additionally, we have tested our new completion design in the Pronghorn field utilizing cemented liners and plug-and-perf technology and are encouraged by the results. As a result of these successes, we plan to use this completion technique on all future wells drilled in the area.

We have completed the construction of our gas processing plant located south of Belfield, North Dakota, which has a processing capacity of 35 MMcf/d and which primarily processes production from the Pronghorn area. In November 2012, we began connecting other operators' wells to the plant, and we added inlet compression during 2013 in order to fully utilize the plant's processing capability. Currently, there is inlet compression in place to process 35 MMcf/d, and as of December 31, 2013 the plant was processing 18 MMcf/d. In May 2012, we sold a 50% ownership interest in the plant, gathering systems and related facilities. We retained a 50% ownership interest and continue to operate the Belfield plant and facilities.

Hidden Bench/Tarpon Fields. Our Hidden Bench and Tarpon fields in McKenzie County, North Dakota target the Bakken and Three Forks formations and encompass approximately 66,800 gross (37,400 net) developed and undeveloped acres and 8,800 gross (6,300 net) developed and undeveloped acres, respectively, as of December 31, 2013. Net production at Hidden Bench/Tarpon averaged 13.4 MBOE/d in the fourth quarter of 2013, which represents a 31% increase from 10.2 MBOE/d in the third quarter of 2013. We have also implemented our new completion design at our Hidden Bench field, utilizing cemented liners and plug-and-perf technology, which has generated positive results. In addition, we have tested a high density drilling pilot at our Hidden Bench field and are currently analyzing the resulting data. In the Tarpon field, we have drilled six productive wells as of December 31, 2013. We had previously planned to drill most of the remaining Tarpon development wells during 2013 but have experienced delays resulting from the U.S. Forest Service's requirement to perform an Environmental Assessment prior to the issuance of federal drilling permits for these wells. We anticipate that we will be able to resume drilling in 2014, and we have begun permitting additional wells for 2014.

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Missouri Breaks Field. As of December 31, 2013, we had approximately 98,600 gross (64,300 net) developed and undeveloped acres at our Missouri Breaks field located in Richland County, Montana and McKenzie County, North Dakota. In the fourth quarter of 2013, net production from the Missouri Breaks field averaged 3.8 MBOE/d, representing a 31% increase from 2.9 MBOE/d in the third quarter of 2013. During 2013, we implemented our new completion design at this field, utilizing cemented liners, plug-and-perf technology and higher sand volumes, and the new design has improved initial production rates. We have drilled successful wells on the western, eastern and southern portions of our acreage in this area.

Redtail Field. Our Redtail field in the Weld County, Colorado portion of the DJ Basin targets the Niobrara formation and encompasses approximately 169,700 gross (122,300 net) developed and undeveloped acres as of December 31, 2013. In September 2013, we completed the acquisition of approximately 47,800 gross (32,100 net) acres at our Redtail field, including interests in one producing well. Our development plan at Redtail currently includes drilling up to eight Niobrara "B" wells per spacing unit and eight Niobrara "A" wells per spacing unit. In 2014, we plan to test a high-density pattern in the Niobrara "A", "B" and "C" zones drilling 32 wells per spacing unit. As of December 31, 2013, we had three drilling rigs operating in this area, and we plan to add another rig in 2014. We implemented a new completion design in this field utilizing larger proppant volumes, which has been yielding improved production results, and we are currently evaluating the use of cemented liners in the Redtail field.

The associated gas produced with the Niobrara oil must be processed before being sold, and we are nearing completion of the construction of a gas processing plant for this area. The plant's initial inlet capacity will be 15 MMcf/d, and we plan to further expand the plant's capacity to 60 MMcf/d in 2015. We anticipate having the plant online in early 2014.

Permian Basin Region

Our Permian Basin operations include assets in Texas and New Mexico. As of December 31, 2013, the Permian Basin region contributed 127.1 MMBOE (84% oil) of estimated proved reserves to our portfolio of operations, which represented 29% of our total estimated proved reserves and contributed 12.3 MBOE/d of average daily production in the fourth quarter of 2013.

North Ward Estes Field. The North Ward Estes field includes six base leases with 100% working interests in approximately 62,300 gross (60,500 net) developed and undeveloped acres in Ward and Winkler counties, Texas. Current production from our enhanced oil recovery ("EOR") project is from the Yates formation at 2,600 feet, which is the primary producing zone, with additional production from other zones including the Queen at 3,000 feet.

The North Ward Estes field has been responding positively to the water and CO2 floods that we initiated in May 2007. We are currently injecting CO2 in one of the largest phases of our eight-phase project at North Ward Estes, and several of the phases of the CO2 flood are continuing to respond. In the fourth quarter of 2013, production from the field averaged 9.8 MBOE/d, which represents a 2% increase from 9.6 MBOE/d in the third quarter of 2013. As of December 31, 2013, we were injecting approximately 390 MMcf/d of CO2 in this field, over half of which is recycled.

North Ward Estes' proved reserves at December 31, 2013 were 39% proved undeveloped. In order to fully develop the reserves at this field within our currently planned timeframe, we will need to utilize significant quantities of purchased CO2. As of December 31, 2013, we currently have under contract 100% of the future CO2 volumes that we believe are necessary to develop the field's PUDs. In addition, we are currently in negotiations and planning for future sources of CO2 capable of generating sufficient quantities to carry out the development of all probable and possible reserves at North Ward Estes. However, we cannot provide absolute assurance with respect to the timing or actual quantities of CO2 that will be obtainable for the development of this field's oil and gas reserves.

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Big Tex Prospect. As of December 31, 2013, we had accumulated approximately 52,300 gross (40,900 net) developed and undeveloped acres at our Big Tex prospect in Pecos, Reeves and Ward counties, Texas in the Delaware Basin. Prospective formations include the Brushy Canyon, Bone Spring and Wolfcamp horizons. In October 2013, we sold approximately 45,000 gross (32,200 net) acres, including interests in certain producing oil and gas wells, as well as undeveloped acreage, in our Big Tex prospect. Refer to "Acquisitions and Divestitures" in Item 1 of this Annual Report on Form 10-K for more information on this divestiture.

Other

Our other operations primarily relate to assets in Arkansas, Louisiana, Michigan, Oklahoma and Texas. As of December 31, 2013, these properties contributed 14.4 MMBOE (31% oil) of proved reserves to our portfolio of operations, which represented 3% of our total estimated proved reserves and contributed 4.0 MBOE/d of average daily production in the fourth quarter of 2013. In Michigan, we also operate the West Branch and Reno gas processing plants. The West Branch plant gathers production from the Clayton unit, West Branch field and other smaller fields.

Reserves

As of December 31, 2013, all of our oil and gas reserves are attributable to properties within the United States. A summary of our oil and gas reserves as of December 31, 2013 based on average fiscal-year prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period ended December 31, 2013) is as follows:

	Oil (MBbl)	NGLs (MBbl)	Natural Gas (MMcf)	Total (MBOE)
Proved reserves				
Developed	198,204	23,721	183,129	252,446
Undeveloped	149,217	21,148	94,385	186,096
Total proved—December 31, 2013	347,421	44,869	277,514	438,542
Probable reserves				
Developed	748	139	6,832	2,026
Undeveloped	108,520	22,191	260,723	174,165
Total probable—December 31, 2013	109,268	22,330	267,555	176,191
Possible reserves				
Developed	1,989	387	1,746	2,667
Undeveloped	135,234	24,220	162,034	186,460
Total possible—December 31, 2013	137,223	24,607	163,780	189,127

Proved reserves. Estimates of proved developed and undeveloped reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

In 2013, total extensions and discoveries of 108.8 MMBOE were primarily attributable to successful drilling in our Redtail, Sanish, Missouri Breaks, Hidden Bench and Pronghorn fields. The new wells drilled in these areas and their related PUD locations added during the year increased our proved reserves.

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In 2013, total sales of minerals in place of 43.8 MMBOE were primarily attributable to the disposition of the Postle Properties, further described in “Acquisitions and Divestitures” within Item 1 of this Annual Report on Form 10-K, which decreased our proved reserves.

In 2013, total purchases of minerals in place of 17.1 MMBOE were primarily attributable to the acquisition of 121 producing oil and gas wells and undeveloped acreage in the Williston Basin, further described in “Acquisitions and Divestitures” within Item 1 of this Annual Report on Form 10-K, which increased our proved reserves.

In 2013, revisions to previous estimates increased proved developed and undeveloped reserves by a net amount of 12.0 MMBOE. Included in these revisions were (i) 4.9 MMBOE of upward adjustments caused by higher crude oil and natural gas prices incorporated into our reserve estimates at December 31, 2013 as compared to December 31, 2012 and (ii) 7.1 MMBOE of net upward adjustments attributable to reservoir analysis and well performance.

Proved undeveloped reserves. Our PUD reserves increased 36% or 49.2 MMBOE on a net basis from December 31, 2012 to December 31, 2013. The following table provides a reconciliation of our PUDs for the year ended December 31, 2013:

	Total (MBOE)
PUD balance—December 31, 2012	136,896
Converted to proved developed through drilling (1)(3)	(27,782)
Converted to proved developed at EOR projects (2)(3)	(12,364)
Added from revisions, extensions and discoveries	90,519
Removed for five-year rule	(602)
Removed due to low commodity prices	(143)
Purchased	12,745
Sold	(13,173)
PUD balance—December 31, 2013	186,096

(1) We incurred $701.5 million in capital expenditures, or $25.25 per BOE, to drill and bring on-line these PUD quantities.

(2) Amount relates to PUD volumes that became proved developed reserves during 2013 at our CO2 EOR project in the North Ward Estes field, at a cost of $40.35 per BOE.

(3) Combining the PUD drilling conversions with the PUD EOR conversions, we converted PUDs to proved developed reserves at a cost of $29.90 per BOE during 2013.

During the year we added 90.5 MMBOE of gross PUD volumes, and this increase in proved undeveloped reserves was primarily due to additional PUD locations added based on successful drilling in the Northern and Central Rockies areas and additional PUD reserves being assigned to our North Ward Estes EOR project.

Based on our 2013 year end independent engineering reserve report, we will drill all of our individual PUD drilling locations within five years. However, we do have certain quantities of proved undeveloped reserves in the North Ward Estes field that will remain in the PUD category for periods extending beyond five years because of certain external factors that preclude the development of the North Ward Estes enhanced oil recovery PUDs all at once. Due to the large areal extent of the field, the CO2 EOR project will progress through the field in a sequential manner as earlier injection areas are completed and new injection areas are initiated. External factors that preclude the initiation of the CO2 project throughout the field at the same time include: (i) the volume of injection water necessary to re-pressure the reservoir in advance of the CO_2 injection, (ii) the volume of purchased and recycled CO_2 necessary to be injected to process the oil in the reservoir, and (iii) the equipment and manpower necessary to build the infrastructure and prepare the wells for the EOR project. Our staged development plan is designed to expand the project as quickly and efficiently as possible to fully develop the field.

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Probable reserves. Estimates of probable developed and undeveloped reserves are inherently imprecise. When producing an estimate of the amount of oil and gas that is recoverable from a particular reservoir, an estimated quantity of probable reserves is an estimate that is as likely as not to be achieved. Estimates of probable reserves are also continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

We use deterministic methods to estimate probable reserve quantities, and when deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain and even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserve estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Increases in probable reserves during 2013 were primarily attributable to 724 new probable well locations that were added in 2013 as a result of our drilling activity across the Rocky Mountains region. During 2013, 31.3 MMBOE of probable reserves were converted to proved reserves at our North Ward Estes field, our Redtail field and various fields in the Northern Rocky Mountains.

Possible reserves. Estimates of possible developed and undeveloped reserves are also inherently imprecise. When producing an estimate of the amount of oil and gas that is recoverable from a particular reservoir, an estimated quantity of possible reserves is an estimate that might be achieved, but only under more favorable circumstances than are likely. Estimates of possible reserves are also continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

We use deterministic methods to estimate possible reserve quantities, and when deterministic methods are used to estimate possible reserve quantities, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir. Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and we believe that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

Possible reserves increased during 2013 primarily due to successful drilling at our Redtail, Sanish, Parshall, Lewis & Clark/Pronghorn and Hidden Bench fields. During 2013, 27.0 MMBOE of possible reserves were converted to probable at our Redtail field and various other fields in the Northern Rocky Mountains, and 19.7 MMBOE of possible reserves were converted to proved at certain fields in the Northern Rocky Mountains.

At December 31, 2013, our probable reserves were estimated to be 176.2 MMBOE and our possible reserves were estimated to be 189.1 MMBOE, for a total of 365.3 MMBOE. The EOR project at our North Ward Estes field represented 94.1 MMBOE, or 26%, of our total 365.3 MMBOE probable and possible reserve quantities. In order to fully develop the EOR probable and possible reserves at North Ward Estes, we will need to utilize significant quantities of purchased CO_2. We are currently in negotiations and planning for future sources capable of generating sufficient CO_2 quantities to carry out the development of all probable and possible reserves at North Ward Estes. However, the availability of future CO_2 supplies is subject to uncertainty and may require significant future capital expenditures by us, and we cannot therefore provide assurance with respect to the timing or actual quantities of CO_2 that will be obtainable for the development of such reserves.

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Preparation of reserves estimates. We maintain adequate and effective internal controls over the reserve estimation process as well as the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interests and production data. All field and reservoir technical information, which is updated annually, is assessed for validity when the reservoir engineers hold technical meetings with geoscientists, operations and land personnel to discuss field performance and to validate future development plans. Current revenue and expense information is obtained from our accounting records, which are subject to external quarterly reviews, annual audits and their own set of internal controls over financial reporting. Internal controls over financial reporting are assessed for effectiveness annually using the criteria set forth in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. All current financial data such as commodity prices, lease operating expenses, production taxes and field commodity price differentials are updated in the reserve database and then analyzed to ensure that they have been entered accurately and that all updates are complete. Our current ownership in mineral interests and well production data are also subject to the aforementioned internal controls over financial reporting, and they are incorporated into the reserve database as well and verified to ensure their accuracy and completeness. Once the reserve database has been entirely updated with current information, and all relevant technical support material has been assembled, our independent engineering firm Cawley, Gillespie & Associates, Inc. ("CG&A") meets with our technical personnel in our Denver and Midland offices to review field performance and future development plans. Following these reviews, the reserve database and supporting data is furnished to CG&A so that they can prepare their independent reserve estimates and final report. Access to our reserve database is restricted to specific members of the reservoir engineering department.

CG&A is a Texas Registered Engineering Firm. Our primary contact at CG&A is Mr. Robert D. Ravnaas, President. Mr. Ravnaas is a State of Texas Licensed Professional Engineer. See Exhibit 99.2 of this Annual Report on Form 10-K for the Report of Cawley, Gillespie & Associates, Inc. and further information regarding the professional qualifications of Mr. Ravnaas.

Our Vice President of Reservoir Engineering and Acquisitions is responsible for overseeing the preparation of the reserves estimates. He has over 29 years of experience, the majority of which has involved reservoir engineering and reserve estimation, and he holds a Bachelor's degree in petroleum engineering from the Colorado School of Mines. He is also a member of the Society of Petroleum Engineers.

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Acreage

The following table summarizes gross and net developed and undeveloped acreage by state at December 31, 2013. Net acreage is our percentage ownership of gross acreage. Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross(2)	Net(2)	Gross	Net
California	25,548	3,606	-	-	25,548	3,606
Colorado	61,579	42,555	179,242	116,629	240,821	159,184
Louisiana	40,074	11,691	101,325	90,862	141,399	102,553
Michigan	139,351	61,064	291,960	247,996	431,311	309,060
Montana	91,973	55,425	136,964	81,730	228,937	137,155
New Mexico	16,665	5,427	78,190	56,668	94,855	62,095
North Dakota	553,050	316,872	365,538	261,008	918,588	577,880
Oklahoma	56,645	28,392	406	68	57,051	28,460
Texas	260,935	147,963	84,214	60,849	345,149	208,812
Utah	35,826	18,370	406,522	240,108	442,348	258,478
Wyoming	95,725	55,835	49,312	36,072	145,037	91,907
Other (1)	9,810	4,503	912	434	10,722	4,937
Total	1,387,181	751,703	1,694,585	1,192,424	3,081,766	1,944,127

(1) Other includes Alabama, Arkansas, Kansas, Mississippi and Nebraska.

(2) Out of a total of approximately 1,694,585 gross (1,192,424 net) undeveloped acres as of December 31, 2013, the portion of our net undeveloped acres that is subject to expiration over the next three years, if not successfully developed or renewed, is approximately 13% in 2014, 27% in 2015 and 22% in 2016.

Production History

The following table presents historical information about our produced oil and gas volumes:

	Year Ended December 31,		
	2013	2012	2011
Oil production (MMBbl)	27.0	23.1	18.3
NGL production (MMBbl)	2.8	2.8	2.1
Natural gas production (Bcf)	26.9	25.8	26.4
Total production (MMBOE)	34.3	30.2	24.8
Daily production (MBOE/d)	94.1	82.5	67.9
North Ward Estes field production (1)			
Oil production (MMBbl)	2.9	2.8	2.6
NGL production (MMBbl)	0.4	0.3	0.4
Natural gas production (Bcf)	0.3	0.3	0.4
Total production (MMBOE)	3.4	3.2	3.0
Sanish field production (1)			
Oil production (MMBbl)	9.8	9.0	6.5
NGL production (MMBbl)	1.1	1.2	0.8
Natural gas production (Bcf)	4.8	3.6	2.2
Total production (MMBOE)	11.7	10.8	7.7

Average sales prices (before the effects of hedging):			
Oil (per Bbl)	$ 90.39	$ 83.86	$ 88.61
NGLs (per Bbl)	$ 40.41	$ 39.36	$ 52.38
Natural gas (per Mcf)	$ 4.04	$ 3.42	$ 4.92
Average production costs:			
Production costs (per BOE) (2)	$ 11.94	$ 11.92	$ 11.77

(1) The North Ward Estes and Sanish fields were our only fields that contained 15% or more of our total proved reserve volumes as of December 31, 2013.

(2) Production costs reported above exclude from lease operating expenses ad valorem taxes of $20.1 million ($0.59 per BOE), $16.3 million ($0.54 per BOE) and $13.9 million ($0.56 per BOE) for the years ended December 31, 2013, 2012 and 2011, respectively.

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Productive Wells

The following table summarizes gross and net productive oil and natural gas wells by region at December 31, 2013. A net well is our percentage ownership of a gross well. Wells in which our interest is limited to royalty and overriding royalty interests are excluded.

	Oil Wells		Natural Gas Wells		Total Wells(1)	
	Gross	Net	Gross	Net	Gross	Net
Rocky Mountains	3,441	1,082	413	221	3,854	1,303
Permian Basin	4,091	1,727	386	122	4,477	1,849
Other (2)	479	217	1,666	553	2,145	770
Total	8,011	3,026	2,465	896	10,476	3,922

(1) 141 wells have multiple completions. These 141 wells contain a total of 349 completions. One or more completions in the same bore hole are counted as one well.

(2) Other primarily includes oil and gas properties in Arkansas, Louisiana, Michigan, Oklahoma and Texas.

We have an interest in or operate 33 EOR projects, which include either secondary (waterflood) or tertiary (CO2 injection) recovery efforts, and aggregate production from such EOR fields averaged 15.5 MBOE/d during 2013 or 16% of our 2013 daily production. For these areas, we need to use enhanced recovery techniques in order to maintain oil and gas production from these fields.

Drilling Activity

We are engaged in numerous drilling activities on properties presently owned, and we intend to drill or develop other properties acquired in the future. The following table sets forth our drilling activity for the last three years. A dry well is an exploratory, development or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well. A productive well is an exploratory, development or extension well that is not a dry well. The information below should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and quantities of reserves found.

	Gross Wells			Net Wells		
	Productive	Dry	Total	Productive	Dry	Total
2013:						
Development	376	1	377	185.5	1	186.5
Exploratory	43	8	51	35.2	7.5	42.7
Total	419	9	428	220.7	8.5	229.2
2012:						
Development	324	-	324	140.4	-	140.4
Exploratory	68	5	73	47.8	4.7	52.5
Total	392	5	397	188.2	4.7	192.9
2011:						
Development	218	3	221	93.9	1.5	95.4
Exploratory	60	3	63	36.6	3.0	39.6
Total	278	6	284	130.5	4.5	135.0

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As of December 31, 2013, 23 operated drilling rigs were active on our properties. The breakdown of our operated rigs by geographic area is as follows:

	Drilling Rigs
Northern Rocky Mountains	18
Central Rocky Mountains	3
North Ward Estes	2
Total	23

Hydraulic Fracturing

Hydraulic fracturing is a common practice in the oil and gas industry that is used to stimulate production of hydrocarbons from tight oil and gas formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. This process has typically been regulated by state oil and gas commissions. However, as described in more detail in "Business – Regulation – Environmental Regulations – Hydraulic Fracturing" in Item 1 of this Annual Report on Form 10-K, the EPA has initiated the regulation of hydraulic fracturing; other federal agencies are examining hydraulic fracturing; and federal legislation is pending with respect to hydraulic fracturing. We have utilized hydraulic fracturing in the completion of our wells in our most active areas located in the states of Colorado, Michigan, Montana, North Dakota and Texas, and we plan to continue to utilize this completion methodology.

Whiting's proved undeveloped reserve quantities that are associated with hydraulic fracture treatments consist of substantially all of our proved undeveloped reserves, or 186.1 MMBOE.

In November 2010, we had a well control incident involving one well in our Sanish field, whereby the North Dakota Industrial Commission ("NDIC") filed a complaint against Whiting alleging the violation of regulations. This matter resulted in us entering into a consent agreement with the NDIC, pursuant to which we paid $4,357 in costs, donated $15,000 to the North Dakota Abandoned Oil and Gas Well Plugging and Site Reclamation Fund, and agreed to implement certain operational procedures. In addition, on February 13, 2014, we had a well control incident during drilling operations involving one well in our Hidden Bench field in North Dakota. The well was quickly brought under control with no liquids leaving the location, and there were no resulting injuries. Appropriate regulatory agencies were notified of the incident. Other than these incidents, we are not aware of any environmental incidents, citations or suits related to hydraulic fracturing operations involving oil and gas properties that we operate or our non-operated interests.

In order to minimize any potential environmental impact from hydraulic fracture treatments, we have taken the following steps:

- we follow fracturing and flowback procedures that comply with or exceed NDIC or other state requirements;
- we train all company and contract personnel, who are responsible for well preparation, fracture stimulation and flowback, on our procedures;
- we have implemented the incremental procedures of running a well casing caliper; visually inspecting the surface joint of intermediate casing; and if a lighter wall joint of casing or drilling wear is detected, the minimum burst pressure is reduced accordingly;
- for wells that are within one mile of major bodies of water or locations that lead to bodies of water, we construct sufficient berming around the well location prior to initiating fracturing operations;
-

we run fracturing strings in certain situations when extra precaution is warranted, such as where the anticipated maximum treating pressure for the well is greater than the pressure rating of the intermediate casing or in areas located within one mile of major bodies of water; and

- we are constructing a facility in North Dakota to treat and dispose of flow fluids from well stimulations.

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While we do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations, we do have general liability and excess liability insurance policies that we believe would cover third-party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies.

Delivery Commitments

Our production sales agreements contain customary terms and conditions for the oil and natural gas industry; generally provide for sales based on prevailing market prices in the area; and generally have terms of one year or less.

We have also entered into physical delivery contracts which require us to deliver fixed volumes of natural gas and crude oil. As of December 31, 2013, we had delivery commitments of 4.0 Bcf of natural gas (or 15% of total 2013 natural gas production) for the year ended December 31, 2014. These contracts relate to gas production at our Boies Ranch field in Rio Blanco County, Colorado and our Flat Rock field in Uintah County, Utah. We believe that our current production and proved reserves are adequate to meet these delivery commitments. As of December 31, 2013, we also had delivery commitments of 9.1 MMBbl of crude oil (or 34% of total 2013 oil production), 11.0 MMBbl (41%), 12.8 MMBbl (47%), 14.6 MMBbl (54%) and 16.4 MMBbl (61%) for the years ended December 31, 2015, 2016, 2017, 2018 and 2019, respectively. These contracts are tied to oil production at our Redtail field in the DJ Basin in Weld County, Colorado, and we expect to fulfill these delivery commitments from the future production from this field. See "Quantitative and Qualitative Disclosures about Market Risk" in Item 7A of this Annual Report on Form 10-K for more information about our delivery commitments under these agreements.

Item 3. Legal Proceedings

Whiting is subject to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business. It is management's opinion that all claims and litigation we are involved in are not likely to have a material adverse effect on our consolidated financial position, cash flows or results of operations.

Item 4. Mine Safety Disclosures

Not applicable.

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EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information, as of February 14, 2014, regarding the executive officers of Whiting Petroleum Corporation:

Name	Age	Position
James J. Volker	67	Chairman and Chief Executive Officer
James T. Brown	61	President and Chief Operating Officer
Mark R. Williams	57	Senior Vice President, Exploration and Development
Bruce R. DeBoer	61	Vice President, General Counsel and Corporate Secretary
Heather M. Duncan	43	Vice President, Human Resources
Steven A. Kranker	52	Vice President, Reservoir Engineering and Acquisitions
Rick A. Ross	55	Vice President, Operations
David M. Seery	59	Vice President, Land
Michael J. Stevens	48	Vice President and Chief Financial Officer
Brent P. Jensen	44	Controller and Treasurer

The following biographies describe the business experience of our executive officers:

James J. Volker joined us in August 1983 as Vice President of Corporate Development and served in that position through April 1993. In March 1993, he became a contract consultant to us and served in that capacity until August 2000, at which time he became Executive Vice President and Chief Operating Officer. Mr. Volker was appointed President and Chief Executive Officer and a director in January 2002 and Chairman of the Board in January 2004. Effective January 1, 2011, Mr. Volker stepped down as President, but remains Chairman and Chief Executive Officer. Mr. Volker was co-founder, Vice President and later President of Energy Management Corporation from 1971 through 1982. He has 42 years of experience in the oil and gas industry. Mr. Volker has a Bachelor's degree in finance from the University of Denver, an MBA from the University of Colorado and has completed H. K. VanPoolen and Associates' course of study in reservoir engineering.

James T. Brown joined us in May 1993 as a consulting engineer. In March 1999, he became Operations Manager; in January 2000, he became Vice President of Operations; and in May 2007, he became Senior Vice President. Effective January 1, 2011, Mr. Brown was elected President and Chief Operating Officer. Mr. Brown has 39 years of oil and gas experience in the Rocky Mountains, Gulf Coast, California and Alaska. Mr. Brown is a graduate of the University of Wyoming with a Bachelor's degree in civil engineering and the University of Denver with an MBA.

Mark R. Williams joined us in December 1983 as Exploration Geologist and has been Vice President of Exploration and Development since December 1999. Mr. Williams was elected Senior Vice President, Exploration and Development effective January 1, 2011. He has 33 years of domestic and international experience in the oil and gas industry. Mr. Williams holds a Master's degree in geology from the Colorado School of Mines and a Bachelor's degree in geology from the University of Utah.

Bruce R. DeBoer joined us as Vice President, General Counsel and Corporate Secretary in January 2005. From January 1997 to May 2004, Mr. DeBoer served as Vice President, General Counsel and Corporate Secretary of Tom Brown, Inc., an independent oil and gas exploration and production company. Mr. DeBoer has 34 years of experience in managing the legal departments of several independent oil and gas companies. He holds a Bachelor of Science degree in political science from South Dakota State University and received his J.D. and MBA degrees from the University of South Dakota.

Heather M. Duncan joined us in February 2002 as Assistant Director of Human Resources and in January 2003 became Director of Human Resources. In January 2008, she was appointed Vice President of Human Resources. Ms. Duncan has 17 years of human resources experience in the oil and gas industry. She holds a Bachelor of Arts degree in anthropology and an MBA from the University of Colorado. She is a certified Senior Professional in Human Resources.

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Steven A. Kranker joined us in March 2013 as First Director – Acquisitions and Reservoir Engineering and became Vice President of Reservoir Engineering and Acquisitions in July 2013. Prior to joining Whiting, Mr. Kranker held positions at several companies engaged in oil and gas exploration and development, including Manager of Reserves at Bill Barrett Corporation from June 2012 to March 2013, President of Earth Energy Reserves, Inc. from July 2010 to June 2012, and various positions at Forest Oil Corporation, including Corporate Engineering Manager, from May 2001 to July 2010. Mr. Kranker has 29 years of acquisition and reservoir engineering experience, including Brunei Shell Petroleum, Arco Alaska Inc., Maxus Exploration, Conoco Inc. and Shell Western E&P Inc. He received his Bachelor of Science degree in petroleum engineering from the Colorado School of Mines. Mr. Kranker is a member of the Society of Petroleum Engineers.

Rick A. Ross joined us in March 1999 as an Operations Manager. In May 2007, he became Vice President of Operations. Mr. Ross has 31 years of oil and gas experience, including 17 years with Amoco Production Company where he served in various technical and managerial positions. Mr. Ross holds a Bachelor of Science degree in mechanical engineering from the South Dakota School of Mines and Technology. He is a registered Professional Engineer, a member of the Society of Petroleum Engineers and was a past Chairman of the North Dakota Petroleum Council.

David M. Seery joined us as our Manager of Land in July 2004 as a result of our acquisition of Equity Oil Company, where he was Manager of Land and Manager of Equity’s Exploration Department, positions he had held for more than five years. He became our Vice President of Land in January 2005. Mr. Seery has 33 years of land experience including staff and managerial positions with Marathon Oil Company. Mr. Seery holds a Bachelor of Science degree in business administration from the University of Montana. He is a registered Land Professional and has held various duties with the Denver Association of Petroleum Landmen.

Michael J. Stevens joined us in May 2001 as Controller, became Treasurer in January 2002 and became Vice President and Chief Financial Officer in March 2005. His 27 years of oil and gas experience includes eight years of service in various positions including Chief Financial Officer, Controller, Secretary and Treasurer at Inland Resources Inc., a company engaged in oil and gas exploration and development. He spent seven years in public accounting with Coopers & Lybrand in Minneapolis, Minnesota. He is a graduate of Mankato State University of Minnesota and is a Certified Public Accountant.

Brent P. Jensen joined us in August 2005 as Controller, and he became Controller and Treasurer in January 2006. He was previously with PricewaterhouseCoopers L.L.P. in Houston, Texas, where he held various positions in their oil and gas audit practice since 1994, which included assignments of four years in Moscow, Russia and three years in Milan, Italy. He has 20 years of oil and gas accounting experience and is a Certified Public Accountant. Mr. Jensen holds a Bachelor of Arts degree from the University of California, Los Angeles.

Executive officers are elected by, and serve at the discretion of, the Board of Directors. There are no family relationships between any of our directors or executive officers.

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PART II

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Whiting Petroleum Corporation's common stock is traded on the New York Stock Exchange under the symbol "WLL." The following table shows the high and low sale prices for our common stock for the periods presented.

	High	Low
Fiscal Year Ended December 31, 2013		
Fourth quarter (ended December 31, 2013)	$ 70.57	$ 56.40
Third quarter (ended September 30, 2013)	$ 60.65	$ 46.13
Second quarter (ended June 30, 2013)	$ 50.96	$ 42.44
First quarter (ended March 31, 2013)	$ 52.02	$ 43.60
Fiscal Year Ended December 31, 2012		
Fourth quarter (ended December 31, 2012)	$ 48.87	$ 40.19
Third quarter (ended September 30, 2012)	$ 54.86	$ 38.29
Second quarter (ended June 30, 2012)	$ 58.33	$ 35.68
First quarter (ended March 31, 2012)	$ 63.97	$ 46.55

On February 14, 2014, there were 639 holders of record of our common stock.

We have not paid any dividends on our common stock since we were incorporated in July 2003, and we do not anticipate paying any such dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our financial position, cash flows, results of operations, capital requirements and investment opportunities. Except for limited exceptions, our credit agreement restricts our ability to make any dividends or distributions on our common stock. Additionally, the indentures governing our senior and senior subordinated notes contain restrictive covenants that may limit our ability to pay cash dividends on our common stock.

Information relating to compensation plans under which our equity securities are authorized for issuance is set forth in Part III, Item 12 of this Annual Report on Form 10-K.

The following information in this Item 5 of this Annual Report on Form 10-K is not deemed to be "soliciting material" or to be "filed" with the SEC or subject to Regulation 14A or 14C under the Securities Exchange Act of 1934 or to the liabilities of Section 18 of the Securities Exchange Act of 1934, and will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent we specifically incorporate it by reference into such a filing.

The following graph compares on a cumulative basis changes since December 31, 2008 in (a) the total stockholder return on our common stock with (b) the total return on the Standard & Poor's Composite 500 Index and (c) the total return on the Dow Jones U.S. Oil Companies, Secondary Index. Such changes have been measured by dividing (a) the sum of (i) the amount of dividends for the measurement period, assuming dividend reinvestment, and (ii) the difference between the price per share at the end of and the beginning of the measurement period, by (b) the price per share at the beginning of the measurement period. The graph assumes $100 was invested on December 31, 2008 in our common stock, the Standard & Poor's Composite 500 Index and the Dow Jones U.S. Oil Companies, Secondary Index.

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	12/31/08	12/31/09	12/31/10	12/31/11	12/31/12	12/31/13
Whiting Petroleum Corporation	$ 100	$ 214	$ 350	$ 279	$ 259	$ 370
Standard & Poor’s Composite 500 Index	100	123	139	139	158	205
Dow Jones U.S. Oil Companies, Secondary Index	100	139	161	153	160	208

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Item 6. Selected Financial Data

The consolidated statements of income and statements of cash flows information for the years ended December 31, 2013, 2012 and 2011 and the consolidated balance sheet information at December 31, 2013 and 2012 are derived from our audited financial statements included elsewhere in this report. The consolidated statements of income and statements of cash flows information for the years ended December 31, 2010 and 2009 and the consolidated balance sheet information at December 31, 2011, 2010 and 2009 are derived from audited financial statements that are not included in this report. Our historical results include the results from our recent proved property acquisitions beginning on the following dates: properties in North Dakota and Montana, September 20, 2013; properties in Colorado, September 1, 2010; and additional interests in properties in North Ward Estes, November 1, 2009 and October 1, 2009. In addition, our historical results also include the effects of our recent proved property divestitures beginning on the following dates: properties in the Postle field, April 1, 2013; and properties in Texas, October 1, 2013.

	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(dollars in millions, except per share data)				
Consolidated Statements of Income Information:					
Revenues and other income:					
Oil, NGL and natural gas sales	$ 2,666.5	$ 2,137.7	$ 1,860.1	$ 1,475.3	$ 917.5
Gain (loss) on hedging activities	(1.9)	2.3	8.8	23.2	38.8
Amortization of deferred gain on sale	31.7	29.5	13.9	15.6	16.6
Gain on sale of properties	128.6	3.4	16.3	1.4	5.9
Interest income and other	3.4	0.5	0.5	0.6	0.6
Total revenues and other income	2,828.3	2,173.4	1,899.6	1,516.1	979.4
Costs and expenses:					
Lease operating	430.2	376.4	305.5	268.3	237.3
Production taxes	225.4	171.6	139.2	103.9	64.7
Depreciation, depletion and amortization	891.5	684.7	468.2	393.9	394.8
Exploration and impairment	453.2	167.0	84.6	59.4	73.0
General and administrative	138.0	108.6	85.0	64.7	42.3
Interest expense	112.9	75.2	62.5	59.1	64.6
Loss on early extinguishment of debt	4.4	—	—	6.2	—
Change in Production Participation Plan liability	(7.0)	13.8	(0.9)	12.1	3.3
Commodity derivative (gain) loss, net	7.8	(85.9)	(24.8)	7.1	262.2
Total costs and expenses	2,256.4	1,511.4	1,119.3	974.7	1,142.2
Income (loss) before income taxes	571.9	662.0	780.3	541.4	(162.8)

Income tax expense (benefit)	205.9	247.9	288.7	204.8	(55.9)
Net income (loss)	366.0	414.1	491.6	336.7	(106.9)
Net loss attributable to noncontrolling interest	0.1	0.1	0.1	—	—
Net income (loss) available to shareholders	366.1	414.2	491.7	336.7	(106.9)
Preferred stock dividends (1)	(0.5)	(1.1)	(1.1)	(64.0)	(10.3)
Net income (loss) available to common shareholders	$ 365.5	$ 413.1	$ 490.6	$ 272.7	$ (117.2)
Earnings (loss) per common share, basic (2)	$ 3.09	$ 3.51	$ 4.18	$ 2.57	$ (1.18)
Earnings (loss) per common share, diluted (2)	$ 3.06	$ 3.48	$ 4.14	$ 2.55	$ (1.18)
Other Financial Information:					
Net cash provided by operating activities	$ 1,744.7	$ 1,401.2	$ 1,192.1	$ 997.3	$ 453.8
Net cash used in investing activities	$ (1,902.5)	$ (1,780.3)	$ (1,760.0)	$ (914.6)	$ (523.5)
Net cash provided by (used in) financing activities	$ 812.4	$ 408.1	$ 564.8	$ (75.7)	$ 72.1
Capital expenditures	$ 2,772.7	$ 2,171.5	$ 1,804.3	$ 923.8	$ 585.8
Consolidated Balance Sheet Information:					
Total assets	$ 8,833.5	$ 7,272.4	$ 6,045.6	$ 4,648.8	$ 4,029.5
Long-term debt	$ 2,653.8	$ 1,800.0	$ 1,380.0	$ 800.0	$ 779.6
Total equity (3)	$ 3,836.7	$ 3,453.2	$ 3,029.1	$ 2,531.3	$ 2,270.1

(1) The year ended December 31, 2010 includes a cash premium of $47.5 million for the induced conversion of our 6.25% Perpetual Preferred Stock.

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(2) On January 26, 2011, our Board of Directors approved a two-for-one split of the Company's shares of common stock to be effected in the form of a stock dividend effective February 22, 2011. Earnings (loss) per common share, basic and diluted for periods prior to February 2011 have been retroactively adjusted to reflect the stock split.

(3) No cash dividends were declared or paid on our common stock during the periods presented.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Unless the context otherwise requires, the terms "Whiting," "we," "us," "our" or "ours" when used in this Item refer to Whiti Petroleum Corporation, together with its consolidated subsidiaries, Whiting Oil and Gas Corporation and Whiting Programs, Inc. When the context requires, we refer to these entities separately. This document contains forward-looking statements, which give our current expectations or forecasts of future events. Please refer to "Forward-Looking Statements" at the end of this Item for an explanation of these types of statements.

Overview

We are an independent oil and gas company engaged in exploration, development, acquisition and production activities primarily in the Rocky Mountains and Permian Basin regions of the United States. Prior to 2006, we generally emphasized the acquisition of properties that increased our production levels and provided upside potential through further development. Since 2006, we have focused primarily on organic drilling activity and on the development of previously acquired properties, specifically on projects that we believe provide the opportunity for repeatable successes and production growth. We believe the combination of acquisitions, subsequent development and organic drilling provides us with a broad set of growth alternatives and allows us to direct our capital resources to what we believe to be the most advantageous investments.

As demonstrated by our recent capital expenditure programs, we are increasingly focused on a balanced exploration and development program, while continuing to selectively pursue acquisitions that complement our existing core properties. We believe that our significant drilling inventory, combined with our operating experience and cost structure, provides us with meaningful organic growth opportunities. Our growth plan is centered on the following activities:

- pursuing the development of projects that we believe will generate attractive rates of return;
- allocating a portion of our exploration and development budget to leasing and exploring prospect areas;
- maintaining a balanced portfolio of lower risk, long-lived oil and gas properties that provide stable cash flows; and
- seeking property acquisitions that complement our core areas.

We have historically acquired operated and non-operated properties that exceed our rate of return criteria. For acquisitions of properties with additional development and exploration potential, our focus has been on acquiring operated properties so that we can better control the timing and implementation of capital spending. In some instances, we have been able to acquire non-operated property interests at attractive rates of return that established a presence in a new area of interest or that have complemented our existing operations. We intend to continue to acquire both operated and non-operated interests to the extent we believe they meet our return criteria. In addition, our willingness to acquire non-operated properties in new geographic regions provides us with geophysical and geologic data in some cases that leads to further acquisitions in the same region, whether on an operated or non-operated basis.

We continually evaluate our current property portfolio and sell properties when we believe that the sales price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own.

Our revenue, profitability and future growth rate depend on many factors which are beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and gas prices historically have been volatile and may fluctuate widely in the future. The following table highlights the quarterly average NYMEX price trends for crude oil and natural gas prices since the first quarter of 2012:

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	2012				2013			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Crude oil	$ 102.94	$ 93.51	$ 92.19	$ 88.20	$ 94.34	$ 94.23	$ 105.82	$ 97.50
Natural gas	$ 2.72	$ 2.21	$ 2.81	$ 3.41	$ 3.34	$ 4.10	$ 3.58	$ 3.60

Lower oil and natural gas prices may not only decrease our revenues, but may also reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our oil and gas reserves. A substantial or extended decline in oil or natural gas prices may result in impairments of our proved oil and gas properties and may materially and adversely affect our future business, financial condition, cash flows, results of operations, liquidity or ability to finance planned capital expenditures. Lower oil and gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders and which is based on the collateral value of our proved reserves that have been mortgaged to the lenders. Alternatively, higher oil and natural gas prices may result in significant mark-to-market losses being incurred on our commodity-based derivatives, which may in turn cause us to experience net losses.

For a discussion of material changes to our proved, probable and possible reserves from December 31, 2012 to December 31, 2013 and our ability to convert PUDs to proved developed reserves, probable reserves to proved reserves and possible reserves to probable or proved reserves, see “Reserves” in Item 2 of this Annual Report on Form 10-K. Additionally, for a discussion relating to the minimum remaining terms of our leases, see “Acreage” in Item 2 of this Annual Report on Form 10-K, and for a discussion on our need to use enhanced recovery techniques, see “Productive Wells” in Item 2 of this Annual Report on Form 10-K.

2013 Highlights and Future Considerations

Operational Highlights.

Sanish and Parshall Fields. Our Sanish and Parshall fields in Mountrail County, North Dakota target the Bakken and Three Forks formations. Net production in the Sanish and Parshall fields averaged 40.4 MBOE/d for the fourth quarter of 2013, representing a 10% increase from 36.8 MBOE/d in the third quarter of 2013. In 2013, net production in the Sanish and Parshall fields totaled 13.6 MMBOE (an average of 37.3 MBOE/d), representing a 10% increase from 12.4 MMBOE in 2012. As of December 31, 2013, we had four drilling rigs active in the Sanish field. We also initiated three high density pilot programs in the Sanish field and participated in several infill wells in the Parshall field during 2013. We recently completed two infill wells using our new completion design and are encouraged by the initial results.

Lewis & Clark/Pronghorn Fields. Our Lewis & Clark/Pronghorn fields are located primarily in the Stark and Billings counties of North Dakota and run along the Bakken shale pinch-out in the southern Williston Basin. In this area, the Upper Bakken shale is thermally mature, moderately over-pressured, and we believe that it has charged reservoir zones within the immediately underlying Pronghorn Sand and Three Forks formations (Middle Bakken and Lower Bakken Shale is absent). Net production in the Lewis & Clark/Pronghorn fields averaged 15.1 MBOE/d in the fourth quarter of 2013, representing a 6% increase from 14.2 MBOE/d in the third quarter of 2013. As of December 31, 2013, we had four drilling rigs operating in the Pronghorn field, all of which are utilizing drilling pads, with two or three wells from each pad. Additionally, we have tested our new completion design in the Pronghorn field utilizing cemented liners and plug-and-perf technology and are encouraged by the results. As a result of these successes, we plan to use this completion procedure on all future wells drilled in the area.

We have completed the construction of our gas processing plant located south of Belfield, North Dakota, which has a processing capacity of 35 MMcf/d and which primarily processes production from the Pronghorn area. In November 2012, we began connecting other operators’ wells to the plant, and we added inlet compression during 2013 in order to fully utilize the plant's processing capability. Currently, there is inlet compression in place to process 35 MMcf/d, and as of December 31, 2013 the plant was processing 18 MMcf/d. In May 2012, we sold a 50% ownership interest in the plant, gathering systems and related facilities. We retained a 50% ownership interest and continue to operate the Belfield plant and facilities.

Hidden Bench/Tarpon Fields. Our Hidden Bench and Tarpon fields in McKenzie County, North Dakota target the Bakken and Three Forks formations. In the fourth quarter of 2013, net production from the Hidden Bench/Tarpon fields averaged 13.4 MBOE/d, representing a 31% increase from 10.2 MBOE/d in the third quarter of 2013. We have also implemented our new completion design at our Hidden Bench field, utilizing cemented liners and plug-and-perf technology, which has generated positive results. In addition, we have tested a high density drilling pilot at our Hidden Bench field and are currently analyzing the resulting data. In the Tarpon field, we have drilled six productive wells as of December 31, 2013. We had previously planned to drill most of the remaining Tarpon development wells during 2013 but have experienced delays resulting from the U.S. Forest Service's requirement to perform an Environmental Assessment prior to the issuance of federal drilling permits for these wells. We anticipate that we will be able to resume drilling in 2014, and we have begun permitting additional wells for 2014.

Missouri Breaks Field. Our Missouri Breaks field, which is located in Richland County, Montana and McKenzie County, North Dakota, targets the Middle Bakken formation. In the fourth quarter of 2013, net production from the Missouri Breaks field averaged 3.8 MBOE/d, representing a 31% increase from 2.9 MBOE/d in the third quarter of 2013. During 2013, we implemented our new completion design at this field, utilizing cemented liners, plug-and-perf technology and higher sand volumes, and the new design has improved initial production rates. We have drilled successful wells on the western, eastern and southern portions of our acreage in this area.

Redtail Field. Our Redtail field in the Denver Julesberg Basin ("DJ Basin") in Weld County, Colorado targets the Niobrara formation. In September 2013, we completed the acquisition of approximately 47,800 gross (32,100 net) acres at our Redtail field, including interests in one producing well, which brings our total acreage position to approximately 169,700 gross (122,300 net) acres in this play. Our development plan at Redtail currently includes drilling up to eight Niobrara "B" wells per spacing unit and eight Niobrara "A" wells per spacing unit. In 2014, we plan to test a high-density pattern in the Niobrara "A", "B" and "C" zones drilling 32 wells per spacing unit. As of December 31, 2013, we had three drilling rigs operating in this area, and we plan to add another rig in 2014. We implemented a new completion design in this field, utilizing larger proppant volumes, which has been yielding improved production results, and we are currently evaluating the use of cemented liners in the Redtail field.

The associated gas produced with the Niobrara oil must be processed before being sold, and we are nearing completion of the construction of a gas processing plant for this area. The plant's initial inlet capacity will be 15 MMcf/d, and we plan to further expand the plant's capacity to 60 MMcf/d in 2015. We anticipate having the plant online in early 2014.

North Ward Estes Field. The North Ward Estes field is located in the Ward and Winkler counties in Texas, and we continue to have significant development and related infrastructure activity in this field since we acquired it in 2005. Our activity at North Ward Estes to date has resulted in production increases and substantial reserve additions, and our expansion of the CO2 flood in this area continues to generate positive results.

North Ward Estes has been responding positively to the water and CO2 floods that we initiated in May 2007. We are currently injecting CO2 in one of the largest phases of our eight-phase project at North Ward Estes, and several of the phases of the CO2 flood are continuing to respond. Net production from North Ward Estes averaged 9.8 MBOE/d for the fourth quarter of 2013, which represents a 2% increase from 9.6 MBOE/d in the third quarter of 2013. As of December 31, 2013, we were injecting approximately 390 MMcf/d of CO2 into the field, over half of which is recycled.

Financing Highlights. In October 2013, our credit agreement borrowing base increased to $2.8 billion from $2.15 billion based on the collateral value of our proved reserves at the regular redetermination date. Of the $2.8 billion borrowing base, $1.2 billion has been committed by lenders and is available for borrowing. The Company may increase the maximum aggregate amount of commitments under the credit agreement up to the $2.8 billion borrowing base if certain conditions are satisfied, including the consent of lenders participating in the increase. All other terms of the credit agreement remain unchanged.

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In October 2013, we paid $254.0 million to redeem all of our $250.0 million aggregate principal amount of 7% Senior Subordinated Notes due February 2014 (the "2014 Notes"), which consisted of a redemption price of 101.595%. Concurrent with this redemption, we paid all accrued and unpaid interest on the 2014 Notes up to but not including the redemption date. We financed the redemption of the 2014 Notes with proceeds from the issuance of our Senior Notes, as discussed below. As a result of the redemption, we recognized a $4.4 million loss on early extinguishment of debt, which consisted of a cash charge of $4.0 million related to the redemption premium on the 2014 Notes and a non-cash charge of $0.4 million related to the acceleration of unamortized debt issuance costs.

On September 12, 2013, we issued at par $1,100.0 million of 5% Senior Notes due March 2019 and $800.0 million of 5.75% Senior Notes due March 2021. On September 26, 2013, we issued at 101% of par $400.0 million of 5.75% Senior Notes due March 2021. We used the net proceeds from these issuances to repay all of the debt outstanding under our credit agreement, to fund our $260.0 million acquisition of Williston Basin assets and to redeem on October 31, 2013 all $250.0 million aggregate principal amount of our outstanding 7% Senior Subordinated Notes due February 2014. We plan to use the remaining net issuance proceeds for general corporate purposes including capital expenditures.

2014 Exploration and Development Budget. Our current 2014 exploration and development ("E&D") budget is $2.7 billion, which we expect to fund substantially with net cash provided by our operating activities, cash on hand and borrowings under our credit facility. This represents a slight increase from the $2,675.2 million incurred on E&D (which consisted of exploration, development and acreage expenditures) during 2013, and based on this level of capital spending, we are forecasting production growth over our 2013 production level of 34.3 MMBOE. We expect to allocate $2,433.0 million of our 2014 budget to exploration and development activity, $116.0 million for undeveloped acreage and $151.0 million for facilities. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we would adjust our E&D budget accordingly or adjust borrowings outstanding under our credit facility as necessary. Our 2014 E&D budget currently is allocated among our major development areas as indicated in the table below. Of our existing potential projects, we believe these present the opportunity for the highest return and most efficient use of our capital expenditures.

Development Area	2014 Exploration and Development Budget (in millions)
Northern Rockies	$ 1,101.0
Central Rockies	575.0
Non-operated	232.0
CO2 EOR project (1)	203.0
Facilities	151.0
Well work and other	150.0
Exploration (2)	116.0
Undeveloped acreage	116.0
CO2 development (3)	56.0
Total	$ 2,700.0

(1) 2014 planned capital expenditures at our CO2 EOR projects include $104.8 million for North Ward Estes CO2 purchases.

(2)

Comprised primarily of exploration salaries, seismic activities, lease delay rentals and exploratory drilling.

(3) E&D expenditures for the development of organic CO_2 reserves at our Bravo Dome field in New Mexico.

Acquisition and Divestiture Highlights. In October 2013, we completed the sale of approximately 45,000 gross (32,200 net) acres, including our interests in certain producing oil and gas wells and undeveloped acreage, in our Big Tex prospect located in the Delaware Basin for a cash purchase price of $152.0 million (subject to post-closing adjustments), resulting in a pre-tax gain on sale of $13.0 million. Of the total net acres sold, approximately 30,800 net acres are located in Pecos County, Texas, and approximately 1,400 net acres are located in Reeves County, Texas. The producing properties had estimated proved reserves of 1.1 MMBOE as of December 31, 2012, representing 0.3% of our proved reserves as of that date, and generated 0.2 MBOE/d of our third quarter 2013 average daily net production.

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In September 2013, we completed the acquisition of approximately 39,300 gross (17,300 net) acres, including interests in 121 producing oil and gas wells and undeveloped acreage, in the Williston Basin in Williams and McKenzie counties of North Dakota and Roosevelt and Richland counties of Montana for an aggregate unadjusted purchase price of $260.0 million.

In July 2013, we completed the sale of our interests in certain oil and gas producing properties located in our enhanced oil recovery projects in the Postle and Northeast Hardesty fields in Texas County, Oklahoma, including the related Dry Trail plant gathering and processing facility, oil delivery pipeline, our entire 60% interest in the Transpetco CO2 pipeline, crude oil swap contracts and certain other related assets and liabilities (collectively the “Postle Properties”) for a cash purchase price of $809.7 million after selling costs and post-closing adjustments, resulting in a pre-tax gain on sale of $109.7 million. We used the net proceeds from this sale to repay a portion of the debt outstanding under our credit agreement. The Postle Properties consisted of estimated proved reserves of 45.1 MMBOE as of December 31, 2012, representing 11.9% of our proved reserves as of that date, and generated 8% (or 7.6 MBOE/d) of our June 2013 average daily net production.

Results of Operations

The following table sets forth selected operating data for the periods indicated:

	Year Ended December 31,		
	2013	2012	2011
Net production:			
Oil (MMBbl)	27.0	23.1	18.3
NGLs (MMBbl)	2.8	2.8	2.1
Natural gas (Bcf)	26.9	25.8	26.4
Total production (MMBOE)	34.3	30.2	24.8
Net sales (in millions):			
Oil (1)	$ 2,443.7	$ 1,940.5	$ 1,621.5
NGLs	114.0	108.9	108.6
Natural gas (1)	108.8	88.3	130.0
Total oil, NGL and natural gas sales	$ 2,666.5	$ 2,137.7	$ 1,860.1
Average sales prices:			
Oil (per Bbl)	$ 90.39	$ 83.86	$ 88.61
Effect of oil hedges on average price (per Bbl)	(1.13)	(1.25)	(1.67)
Oil net of hedging (per Bbl)	$ 89.26	$ 82.61	$ 86.94
Average NYMEX price (per Bbl)	$ 98.00	$ 94.19	$ 95.14
NGLs (per Bbl)	$ 40.41	$ 39.36	$ 52.38
Natural gas (per Mcf)	$ 4.04	$ 3.42	$ 4.92
Effect of natural gas hedges on average price (per Mcf)	-	0.06	0.04
Natural gas net of hedging (per Mcf)	$ 4.04	$ 3.48	$ 4.96
Average NYMEX price (per Mcf)	$ 3.66	$ 2.79	$ 4.04
Cost and expenses (per BOE):			
Lease operating expenses	$ 12.53	$ 12.46	$ 12.33
Production taxes	$ 6.56	$ 5.68	$ 5.62
Depreciation, depletion and amortization expense	$ 25.96	$ 22.67	$ 18.89
General and administrative expenses	$ 4.02	$ 3.59	$ 3.43

(1) Before consideration of hedging transactions.

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Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $528.8 million to $2,666.5 million when comparing 2013 to 2012. Sales revenue is a function of oil, NGL and gas volumes sold and average commodity prices realized. Our oil sales volumes increased 17%, and our natural gas sales volumes increased 4% between periods, while our NGL sales volumes remained consistent between periods. The oil volume increase resulted primarily from drilling success at our Hidden Bench/Tarpon, Sanish, Parshall, Missouri Breaks, Lewis & Clark/Pronghorn and Redtail fields. During 2013, oil production from our Hidden Bench/Tarpon fields increased 1,770 MBbl, oil production from our Sanish and Parshall fields increased 1,100 MBbl, oil production from our Missouri Breaks field increased 765 MBbl, oil production from our Lewis & Clark/Pronghorn fields increased 765 MBbl, and oil production from our Redtail field increased 610 MBbl over the same period in 2012. These production increases were partially offset by the sale of the Postle Properties in July 2013 and the Whiting USA Trust II ("Trust II") divestiture in March 2012, which divestitures negatively impacted oil production in 2013 by 1,250 MBbl and 295 MBbl, respectively. The gas volume increase between periods was primarily the result of new wells drilled and completed during the past twelve months, which caused increases in associated gas production of 1,380 MMcf at our Hidden Bench/Tarpon fields, 1,330 MMcf at our Sanish and Parshall fields and 870 MMcf at our Lewis & Clark/Pronghorn fields. These gas volume increases were largely offset by normal field production decline across several of our areas, the most notable of which was our Flat Rock field where production volumes decreased 1,080 MMcf when comparing 2013 to 2012. In addition, the Trust II divestiture in March 2012 negatively impacted gas production in 2013 by 545 MMcf.

In addition to the above crude oil and natural gas production-related increases in net revenue were increases in the average sales prices realized for oil, NGLs and natural gas in 2013 compared to 2012. Our average price for oil before the effects of hedging increased 8%, our average price for NGLs increased 3% between periods, and our average price for natural gas before the effects of hedging increased 18% between periods.

Gain on Sale of Properties. During 2013, we sold our interest in the Postle Properties for net proceeds of $809.7 million in cash, which resulted in a pre-tax gain on sale of $109.7 million. Additionally during 2013, we sold our interest in certain producing oil and gas wells and undeveloped acreage in the Big Tex prospect for net proceeds of $152.0 million, which resulted in a pre-tax gain on sale of $13.0 million. There were no other property divestitures resulting in a significant gain or loss on sale during 2013 or 2012.

Lease Operating Expenses. Our lease operating expenses ("LOE") during 2013 were $430.2 million, a $53.8 million increase over the same period in 2012. Higher LOE in 2013 were primarily related to a $45.2 million increase in the cost of oil field goods and services associated with net wells we added during the last twelve months, and an $8.6 million increase in costs at the North Ward Estes CO2 processing facility due to increased production from that field and higher related volumes processed through the plant.

Our lease operating expenses on a BOE basis only increased slightly during 2013. LOE per BOE amounted to $12.53 during 2013, which was up from $12.46 per BOE during 2012. This increase was mainly due to the higher costs of oil field goods and services and CO2 processing facility costs in 2013, as discussed above, partially offset by higher overall production volumes between periods.

Production Taxes. Our production taxes during 2013 were $225.4 million, a $53.8 million increase over the same period in 2012, which increase was primarily due to higher oil, NGL and natural gas sales between periods. Our production taxes, however, are generally calculated as a percentage of net sales revenue before the effects of hedging, and this percentage on a company-wide basis was 8.5% and 8.0% for 2013 and 2012, respectively. Our production tax rate of 8.5% for 2013 was greater than the rate for 2012 due to successful wells completed during the past twelve months in North Dakota, which carries an 11.5% severance tax rate.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense increased $206.8 million in 2013 as compared to 2012. The components of our DD&A expense were as follows (in thousands):

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	Year Ended December 31, 2013	2012
Depletion	$ 876,208	$ 673,789
Depreciation	4,700	3,672
Accretion of asset retirement obligations	10,608	7,263
Total	$ 891,516	$ 684,724

DD&A increased in 2013 primarily due to $202.4 million in higher depletion expense between periods. Of this increase, $105.4 million related to an increase in our overall production volumes during 2013 and $97.0 million related to a higher depletion rate between periods. On a BOE basis, our overall DD&A rate of $25.96 for 2013 was 15% higher than the rate of $22.67 for 2012 due to $2,349.8 million in drilling and development expenditures during the past twelve months, which were partially offset by reserve additions during this same time period.

Exploration and Impairment Costs. Our exploration and impairment costs increased $286.2 million in 2013 as compared to 2012. The components of our exploration and impairment costs were as follows (in thousands):

	Year Ended December 31, 2013	2012
Exploration	$ 94,755	$ 59,117
Impairment	358,455	107,855
Total	$ 453,210	$ 166,972

Exploration costs increased $35.6 million during 2013 as compared to 2012 primarily due to an increase in geological and geophysical ("G&G") activity, higher exploratory dry hole costs, higher delay lease rentals paid and an increase in geology-related general and administrative expenses. G&G costs, such as seismic studies, amounted to $30.4 million during 2013 as compared to $16.6 million during 2012. Exploratory dry hole costs for 2013 totaled $28.7 million, primarily related to eight exploratory dry holes drilled in the Rocky Mountains and Permian Basin regions during 2013. During 2012, on the other hand, we drilled five exploratory dry holes in the Rocky Mountains and Permian Basin regions and in Michigan totaling $18.4 million. Delay lease rentals increased $7.1 million between periods, while geology-related general and administrative expenses increased $5.5 million.

Impairment expense in 2013 primarily related to (i) $267.1 million in non-cash impairment charges for the partial write-down of proved properties, primarily attributable to gas reserves in the Rocky Mountains region and in Michigan, whose net book values exceeded their undiscounted future cash flows, (ii) $70.9 million of amortization of leasehold costs associated with individually insignificant unproved properties and (iii) $18.9 million of impairment write-downs of undeveloped acreage costs for leases that had reached their expiration dates but where no wells had been drilled on such acreage. Impairment expense in 2012 primarily related to (i) the amortization of leasehold costs associated with individually insignificant unproved properties of $54.5 million, (ii) $46.9 million of non-cash proved property impairment write-downs, mainly in the Rocky Mountains region and (iii) $6.1 million of impairment write-downs of undeveloped acreage costs.

General and Administrative Expenses. We report general and administrative expenses net of third-party reimbursements and internal allocations. The components of our general and administrative expenses were as follows (in thousands):

	Year Ended December 31, 2013	2012
	$ 251,593	$ 199,943

General and administrative expenses		
Reimbursements and allocations	(113,599)	(91,370)
General and administrative expense, net	$ 137,994	$ 108,573

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General and administrative expense before reimbursements and allocations increased $51.7 million during 2013 as compared to 2012 primarily due to higher employee compensation and an increase in accrued Production Participation Plan (the "Plan") distributions. However, our general and administrative expenses as a percentage of oil, NGL and natural gas sales remained consistent for 2013 and 2012 at about 5%. Employee compensation increased $28.5 million in 2013 as compared to 2012 due to personnel hired during the past twelve months, general pay increases and higher stock compensation between periods. Accrued distributions under the Plan increased $21.7 million between periods. This increase was primarily due to a one-time charge under the Plan of $21.7 million for the sale of the Postle Properties in the third quarter of 2013 and $8.6 million related to a higher level of Plan net revenues (which have been reduced by lease operating expenses and production taxes pursuant to the Plan formula), which increases were partially offset by higher accrued Plan distributions of $8.6 million at December 31, 2012 due to the Trust II net profits interest divestiture in 2012.

The increase in reimbursements and allocations for 2013 was primarily caused by higher salary costs and a greater number of field workers on Whiting-operated properties.

Interest Expense. The components of our interest expense were as follows (in thousands):

	Year Ended December 31, 2013	2012
Senior Notes and Senior Subordinated Notes	$ 73,983	$ 40,250
Credit agreement	27,978	28,043
Amortization of debt issue costs and debt premium	12,405	9,518
Other	85	148
Capitalized interest	(1,515)	(2,749)
Total	$ 112,936	$ 75,210

The increase in interest expense of $37.7 million between periods was mainly attributable to a $33.7 million increase in the amount of interest incurred on our notes during 2013 as compared to 2012 due to our September 2013 issuance of $1,100.0 million of 5% Senior Notes due 2019 and $1,200.0 million of 5.75% Senior Notes due 2021. Our weighted average debt outstanding during 2013 was $2,263.0 million versus $1,576.6 million for 2012. Our weighted average effective cash interest rate was 4.5% during 2013 compared to 4.3% during 2012.

Commodity Derivative (Gain) Loss, Net. All of our commodity derivative contracts as well as our embedded derivatives are marked-to-market each quarter with fair value gains and losses recognized immediately in earnings, as commodity derivative (gain) loss, net. Cash flow, however, is only impacted to the extent that settlements under these contracts result in making or receiving a payment from the counterparty. Commodity derivative (gain) loss, net amounted to a loss of $7.8 million for 2013 mainly due to the upward shift in the futures curve of forecasted commodity prices ("forward price curve") for crude oil from January 1, 2013 (or the 2013 date on which new contracts were entered into) to December 31, 2013. Commodity derivative (gain) loss, net for 2012, however, resulted in a gain of $85.9 million due to a significant downward shift in the same forward price curve from January 1, 2012 (or the 2012 date on which prior year contracts were entered into) to December 31, 2012.

See Item 7A, "Quantitative and Qualitative Disclosures about Market Risk," for a list of our outstanding derivatives as of February 6, 2014.

Income Tax Expense. Income tax expense totaled $205.9 million for 2013 as compared to $247.9 million of income tax for 2012, a decrease of $42.0 million that was mainly related to $90.1 million in lower pre-tax income between periods, as well as $10.5 million in state tax credits.

Our effective tax rates for 2013 and 2012 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences. Our overall effective tax rate decreased from 37.4% in 2012 to 36.0% for 2013. This decrease in rate is mainly attributable to state tax credits and a reduction to the North Dakota corporate tax rate, which created a one-time benefit during 2013.

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

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $277.6 million to $2,137.7 million in 2012 compared to 2011. Sales revenue is a function of oil, NGL and gas volumes sold and average commodity prices realized. Our oil sales volumes increased 26%, and our NGL sales volumes increased 33% between periods, while our natural gas sales volumes decreased 2%. The oil volume increase resulted primarily from drilling success at our Sanish, Lewis & Clark/Pronghorn and Hidden Bench/Tarpon fields. During 2012, oil production from our Sanish field increased 2,475 MBbl, while oil production from our Lewis & Clark/Pronghorn fields increased 2,150 MBbl compared to 2011, and oil production from our Hidden Bench/Tarpon fields increased 495 MBbl over the same period in 2011. These production increases were partially offset by the Trust II divestiture in March 2012, which divestiture negatively impacted oil production by 915 MBbl in 2012. Our NGL sales volume increases generally relate to drilling success in the same areas as our oil volume increases, such as our Sanish, Lewis & Clark/Pronghorn and Hidden Bench/Tarpon fields. The gas volume decline between periods was primarily the result of normal field production decline across several of our areas, as well as the Trust II divestiture. During 2012, gas production at our Flat Rock field decreased 1,795 MMcf, and gas production at our Canyon field decreased 645 MMcf compared to 2011. In addition, the Trust II divestiture negatively impacted gas production by 1,760 MMcf during 2012. These gas volume declines were partially offset by increases in associated gas production of 2,035 MMcf at our Lewis & Clark/Pronghorn fields and 1,500 MMcf at our Sanish field related to new wells drilled and completed in these areas during the past twelve months.

Partially offsetting the above crude oil and NGL production-related increases in net revenue, were decreases in the average sales prices realized for oil, NGLs and natural gas. Our average price for oil before the effects of hedging decreased 5% in 2012 as compared to 2011, while our average price for NGLs decreased 25%, and our average price for natural gas before the effects of hedging decreased 30% between periods.

Gain (Loss) on Hedging Activities. Our gain (loss) on hedging activities decreased $6.4 million in 2012 as compared to 2011, and it consisted of the following (in thousands):

	Year Ended December 31,	
	2012	2011
Gains (losses) reclassified from AOCI on de-designated hedges	$ 2,338	$ 8,758

Effective April 1, 2009, we elected to de-designate all of our commodity derivative contracts that had been previously designated as cash flow hedges, and we elected to discontinue all hedge accounting prospectively. Accordingly, each period we reclassify from accumulated other comprehensive income (“AOCI”) into earnings unrealized gains and losses (which were frozen in AOCI on the April 1, 2009 de-designation date) upon the expiration of these de-designated crude oil hedges, and we report such non-cash unrealized gains and losses as gain (loss) on hedging activities.

See Item 7A, “Quantitative and Qualitative Disclosures about Market Risk,” for a list of our outstanding derivatives as of February 6, 2014.

Lease Operating Expenses. Our LOE during 2012 were $376.4 million, a $70.9 million increase over the same period in 2011. Higher LOE in 2012 were primarily related to a $68.2 million increase in the cost of oil field goods and services and gas plant operating expenses, both of which were associated with net wells we added during the last twelve months. In addition, well workover activity increased to $81.9 million in 2012, as compared to $79.2 million in 2011, primarily due to a higher number of well workovers being conducted at our Sanish field and at our CO2 project at North Ward Estes. This increase in workover expense was partially offset by a lower number of workovers in our Western Texas district and at our Postle field.

Our lease operating expenses on a BOE basis only slightly increased during 2012. LOE per BOE amounted to $12.46 during 2012, which was up from $12.33 per BOE during 2011. This slight increase was mainly due to the higher costs of oil field goods and services, plant expenses and workover activity in 2012, as discussed above, which were largely offset by higher overall production volumes between periods.

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Production Taxes. Our production taxes during 2012 were $171.6 million, a $32.4 million increase over the same period in 2011, which increase was primarily due to higher oil, NGL and natural gas sales between periods. Our production taxes, however, are generally calculated as a percentage of net sales revenue before the effects of hedging, and this percentage on a company-wide basis was 8.0% and 7.5% for 2012 and 2011, respectively. Our production tax rate of 8.0% for 2012 was greater than the rate for 2011 due to successful wells completed during the past twelve months in North Dakota, which carries an 11.5% severance tax rate.

Depreciation, Depletion and Amortization. Our DD&A expense increased $216.5 million in 2012 as compared to 2011. The components of our DD&A expense were as follows (in thousands):

	Year Ended December 31, 2012	Year Ended December 31, 2011
Depletion	$ 673,789	$ 457,499
Depreciation	3,672	2,688
Accretion of asset retirement obligations	7,263	8,016
Total	$ 684,724	$ 468,203

DD&A increased in 2012 primarily due to $216.3 million in higher depletion expense between periods. Of this increase, $121.1 million related to the increase in our overall production volumes during 2012 and $95.2 million related to a higher depletion rate between periods. On a BOE basis, our overall DD&A rate of $22.67 for 2012 was 20% higher than the rate of $18.89 for 2011 due to $2,031.6 million in drilling and development expenditures during 2012, which were partially offset by reserve additions during this same time period.

Exploration and Impairment Costs. Our exploration and impairment costs increased $82.3 million in 2012 as compared to 2011. The components of our exploration and impairment costs were as follows (in thousands):

	Year Ended December 31, 2012	Year Ended December 31, 2011
Exploration	$ 59,117	$ 45,861
Impairment	107,855	38,783
Total	$ 166,972	$ 84,644

Exploration costs increased $13.3 million during 2012 as compared to 2011 primarily due to higher exploratory dry hole costs. Exploratory dry hole costs for 2012 totaled $18.4 million, primarily related to five exploratory dry holes drilled in the Rocky Mountains and Permian Basin regions and in Michigan during 2012. During 2011, we drilled three exploratory dry holes in the Rocky Mountains and Permian Basin regions and in Texas totaling $4.9 million.

Impairment expense in 2012 and 2011 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties, and such amortization resulted in impairment expense of $54.5 million in 2012 as compared to $34.9 million in 2011. Also included in impairment expense for 2012 is $46.9 million in non-cash impairment charges for the partial write-down of proved properties, mainly in the Rocky Mountains region, whose net book values exceeded their undiscounted future cash flows, whereas 2011 impairment expense only included $3.2 million of non-cash proved property impairment write-downs.

General and Administrative Expenses. We report general and administrative expenses net of third-party reimbursements and internal allocations. The components of our general and administrative expenses were as follows (in thousands):

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	Year Ended December 31, 2012	2011
General and administrative expenses	$ 199,943	$ 153,341
Reimbursements and allocations	(91,370)	(68,356)
General and administrative expense, net	$ 108,573	$ 84,985

General and administrative expense before reimbursements and allocations increased $46.6 million during 2012 as compared to 2011 primarily due to higher employee compensation, an increase in accrued Plan distributions and a $7.8 million increase in professional fees and information technology costs. Employee compensation increased $21.7 million in 2012 as compared to 2011 due to personnel hired during the past twelve months, general pay increases and higher stock compensation between periods. In addition, accrued distributions under the Plan increased general and administrative expenses by $10.7 million when comparing 2012 to 2011. Of this increase in general and administrative expenses related to Plan distributions, $8.6 million related to the Trust II net profits interest divestiture, and $2.1 million related to a higher level of Plan net revenues (which have been reduced by lease operating expenses and production taxes pursuant to the Plan formula).

The increase in reimbursements and allocations for 2012 was primarily caused by higher salary costs and a greater number of field workers on Whiting-operated properties. Our general and administrative expenses as a percentage of oil, NGL and natural gas sales remained consistent for 2012 and 2011 at about 5%.

Interest Expense. The components of our interest expense were as follows (in thousands):

	Year Ended December 31, 2012	2011
Senior Subordinated Notes	$ 40,250	$ 40,250
Credit agreement	28,043	17,049
Amortization of debt issue costs	9,518	8,682
Other	148	109
Capitalized interest	(2,749)	(3,574)
Total	$ 75,210	$ 62,516

The increase in interest expense of $12.7 million between periods was mainly attributable to an $11.0 million increase in the amount of interest incurred on our credit agreement during 2012 as compared to 2011. Our credit agreement interest was higher in 2012 due to a greater amount of borrowings outstanding under this facility. Our weighted average debt outstanding during 2012 was $1,576.6 million versus $1,151.5 million for 2011. Our weighted average effective cash interest rate was 4.3% during 2012 compared to 5.0% during 2011.

Commodity Derivative (Gain) Loss, Net. All of our commodity derivative contracts as well as our embedded derivatives are marked-to-market each quarter with fair value gains and losses recognized immediately in earnings, as commodity derivative (gain) loss, net. Cash flow, however, is only impacted to the extent that settlements under these contracts result in making or receiving a payment from the counterparty. Commodity derivative (gain) loss, net amounted to a gain of $85.9 million for 2012 due to the significant downward shift in the forward price curve for

NYMEX crude oil from January 1, 2012 (or the 2012 date on which new contracts were entered into) to December 31, 2012. Commodity derivative (gain) loss, net for 2011 resulted in a gain of $24.9 million due to a less significant downward shift in the same forward price curve from January 1, 2011 (or the 2011 date on which those prior year contracts were entered into) to December 31, 2011.

Income Tax Expense. Income tax expense totaled $247.9 million for 2012 as compared to $288.7 million of income tax for 2011, a decrease of $40.8 million that was mainly related to $118.3 million in lower pre-tax income between periods.

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Our effective tax rates for 2012 and 2011 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences. Our overall effective tax rate only increased slightly between periods from 37.0% for 2011 to 37.4% for 2012.

Liquidity and Capital Resources

Overview. At December 31, 2013, we had $699.5 million of cash on hand and $3,828.6 million of equity, while at December 31, 2012, we had $44.8 million of cash on hand and $3,445.0 million of equity.

One of the primary sources of variability in our cash flows from operating activities is commodity price volatility, which we partially mitigate through the use of commodity derivative contracts. Oil accounted for 79% and 77% of our total production in 2013 and 2012, respectively. As a result, our operating cash flows are more sensitive to fluctuations in the price for crude oil than to fluctuations in the price for NGLs and natural gas. As of February 6, 2014, we had derivative contracts covering the sale of approximately 47% of our forecasted 2014 oil production volumes.

Cash Flows from 2013 Compared to 2012. During 2013, we generated $1,744.7 million of cash provided by operating activities, an increase of $343.5 million from 2012. Cash provided by operating activities increased primarily due to higher realized sales prices for oil, NGLs and natural gas and higher crude oil and natural gas production volumes during 2013. These positive factors were partially offset by increased lease operating expenses, production taxes, exploration costs, general and administrative and cash interest expense in 2013 as compared to 2012. Refer to “Results of Operations” for more information on the impact of prices and volumes on revenues and for more information on increases and decreases in certain expenses during 2013.

During 2013, cash flows from operating activities plus $2,304.0 million of proceeds from the issuance of our Senior Notes and $968.6 million of proceeds from the sale of properties were used to finance $2,349.8 million of drilling and development expenditures, $1,200.0 million of net repayments under our credit agreement, $422.9 million of oil and gas property acquisitions, $254.0 million for the redemption of our 7% Senior Subordinated Notes due 2014, $42.5 million in investing derivative purchases (net of cash receipts for settlements), $45.3 million for other property and equipment and $29.7 million of debt issuance costs.

Cash Flows from 2012 Compared to 2011. During 2012, we generated $1,401.2 million of cash provided by operating activities, an increase of $209.1 million from 2011. Cash provided by operating activities increased primarily due to higher crude oil and NGL production volumes in 2012. This positive factor was partially offset by lower realized sales prices for oil, NGLs and natural gas and lower natural gas production volumes in 2012, as well as increased lease operating expenses, production taxes, general and administrative and cash interest expense during 2012 as compared to 2011. See “Results of Operations” for more information on the impact of prices and volumes on revenues and for more information on increases in certain expenses during 2012. Cash flows from operating activities plus $420.0 million in net borrowings under our credit agreement, $322.3 million of proceeds from the sale of Trust II units and $69.2 million of proceeds from the sale of oil and gas properties were used to finance $2,050.0 million of drilling and development expenditures and $125.3 million of oil and gas property acquisitions in 2012.

Exploration, Development and Undeveloped Acreage Expenditures. The following chart details our exploration, development and undeveloped acreage expenditures incurred by region (in thousands):

	Year Ended December 31,		
	2013	2012	2011
Rocky Mountains (1)	$ 2,172,462	$ 1,581,934	$ 1,364,324
Permian Basin (2)	346,812	410,154	366,637

Other (3)		155,918		119,431		109,193
Total incurred	$	2,675,192	$	2,111,519	$	1,840,154

(1) For the year ended December 31, 2012, proceeds from the sale of the Belfield gas plant of $66.2 million have been included as a reduction to expenditures in the Rocky Mountains region.

(2) For the years ended December 31, 2013 and 2012, amount includes $21.3 million and $10.8 million, respectively, related to the development of CO_2 reserves for use in our North Ward Estes field EOR project. We did not incur any such costs during the year ended December 31, 2011.

(3) Other primarily includes oil and gas properties in Arkansas, Louisiana, Michigan, Oklahoma and Texas.

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We continually evaluate our capital needs and compare them to our capital resources. Our current 2014 E&D budget is $2.7 billion, which we expect to fund substantially with net cash provided by our operating activities, cash on hand and borrowings under our credit facility. This represents a slight increase from the $2,675.2 million incurred on exploration, development and acreage expenditures during 2013, and based on this level of capital spending, we are forecasting production growth in 2014 over our 2013 production level of 34.3 MMBOE. We expect to allocate $2,433.0 million of our 2014 budget to exploration and development activity, $116.0 million for undeveloped acreage and $151.0 million for facilities. Although we have only budgeted $116.0 million for undeveloped leasehold purchases in 2014, we will continue to selectively pursue property acquisitions that complement our existing core property base. We believe that should additional attractive acquisition opportunities arise or exploration and development expenditures exceed $2.7 billion, we will be able to finance additional capital expenditures with cash on hand, cash flows from operating activities, borrowings under our credit agreement, issuances of additional debt or equity securities, agreements with industry partners or divestitures of certain oil and gas property interests. Our level of exploration, development and acreage expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly depending on available opportunities, commodity prices, cash flows and development results, among other factors. We believe that we have sufficient liquidity and capital resources to execute our business plans over the next 12 months and for the foreseeable future. In addition, with our expected cash flow streams, commodity price hedging strategies, current liquidity levels, access to debt and equity markets and flexibility to modify future capital expenditure programs, we expect to be able to fund all planned capital programs and debt repayments, comply with our debt covenants, and meet other obligations that may arise from our oil and gas operations.

Credit Agreement. Whiting Oil and Gas Corporation (“Whiting Oil and Gas”), our wholly-owned subsidiary, has a credit agreement with a syndicate of banks that as of December 31, 2013 had a borrowing base of $2.8 billion, of which $1.2 billion has been committed by lenders and is available for borrowing. We may increase the maximum aggregate amount of commitments under the credit agreement up to the $2.8 billion borrowing base if certain conditions are satisfied, including the consent of lenders participating in the increase. As of December 31, 2013, we had $1,197.0 million of available borrowing capacity, which was net of $3.0 million in letters of credit and no borrowings outstanding.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves that have been mortgaged to such lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. A portion of the revolving credit facility in an aggregate amount not to exceed $50.0 million may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of ours. As of December 31, 2013, $47.0 million was available for additional letters of credit under the agreement.

The credit agreement provides for interest only payments until April 2016, when the agreement expires and all outstanding borrowings are due. Interest accrues at our option at either (i) a base rate for a base rate loan plus the margin in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.50% or an adjusted LIBOR rate plus 1.00%, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus the margin in the table below. Additionally, we also incur commitment fees as set forth in the table below on the unused portion of the lesser of the aggregate commitments of the lenders or the borrowing base.

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Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans	Commitment Fee
Less than 0.25 to 1.0	0.50%	1.50%	0.375%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	0.75%	1.75%	0.375%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.00%	2.00%	0.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.25%	2.25%	0.50%
Greater than or equal to 0.90 to 1.0	1.50%	2.50%	0.50%

The credit agreement contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of our lenders. Except for limited exceptions, the credit agreement also restricts our ability to make any dividend payments or distributions on our common stock. These restrictions apply to all of the net assets of Whiting Oil and Gas. The credit agreement requires us, as of the last day of any quarter, (i) to not exceed a total debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 4.0 to 1.0 and (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0. We were in compliance with our covenants under the credit agreement as of December 31, 2013.

For further information on the interest rates and loan security related to our credit agreement, refer to the Long-Term Debt footnote in the notes to consolidated financial statements.

Senior Notes and Senior Subordinated Notes. In September 2013, we issued at par $1,100.0 million of 5% Senior Notes due March 2019 and $800.0 million of 5.75% Senior Notes due March 2021, and also in September 2013, we issued at 101% of par an additional $400.0 million of 5.75% Senior Notes due March 2021. In September 2010, we issued at par $350.0 million of 6.5% Senior Subordinated Notes due October 2018. In October 2005, we issued at par $250.0 million of 7% Senior Subordinated Notes due February 2014 ("2014 Notes"). In October 2013, we redeemed all $250.0 million of the outstanding 2014 Notes.

The indentures governing the notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If we were in violation of this covenant, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas Corporation's credit agreement. Additionally, the indentures governing the notes contain restrictive covenants that may limit our ability to, among other things, pay cash dividends, redeem or repurchase our capital stock or our subordinated debt, make investments or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of the assets of ours and our restricted subsidiaries taken as a whole and enter into hedging contracts. These covenants may potentially limit the discretion of our management in certain respects. We were in compliance with these covenants as of December 31, 2013. However, a substantial or extended decline in oil, NGL or natural gas prices may adversely affect our ability to comply with these covenants in the future.

Shelf Registration Statement. We 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 periodically 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.

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Contractual Obligations and Commitments

Schedule of Contractual Obligations. The table below does not include our Production Participation Plan liability of $160.8 million (which amount comprises both the long and short-term portions of this obligation) as of December 31, 2013, since we cannot determine with accuracy the timing or amounts of future payments other than the short-term portion of $73.3 million. The table below also does not include any penalties that may be incurred under our physical delivery contracts, since we cannot predict with accuracy whether we will be subject to any such penalties or the amount and timing of any such penalties if incurred. The following table summarizes our obligations and commitments as of December 31, 2013 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods (in thousands):

	Payments due by period				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (1)	$ 2,650,000	$ -	$ -	$ 350,000	$ 2,300,000
Cash interest expense on debt (2)	891,896	146,750	293,500	287,813	163,833
Derivative contract liability fair value (3)	3,482	3,482	-	-	-
Asset retirement obligations (4)	126,148	9,706	19,243	21,642	75,557
Tax sharing liability (5)	23,856	23,856	-	-	-
Purchase obligations (6)	632,627	82,633	227,531	111,854	210,609
Drilling rig contracts (7)	137,896	87,610	50,286	-	-
Operating leases (8)	28,791	6,279	11,259	9,879	1,374
Construction and drilling contract (9)	44,966	31,066	2,900	11,000	-
Total	$ 4,539,662	$ 391,382	$ 604,719	$ 792,188	$ 2,751,373

(1) Long-term debt consists of the principal amounts of the 6.5% Senior Subordinated Notes due 2018, the 5% Senior Notes due 2019 and the 5.75% Senior Notes due 2021.

(2) Cash interest expense on the 6.5% Senior Subordinated Notes due 2018, the 5% Senior Notes due 2019 and the 5.75% Senior Notes due 2021 is estimated assuming no principal repayment until the due dates of the instruments. No cash interest expense is assumed on the credit facility as there were no borrowings outstanding as of December 31, 2013.

(3) The above derivative obligation at December 31, 2013 primarily consists of (i) a $3.1 million fair value liability for derivative contracts we have entered into on our own behalf, primarily in the form of costless collars, to hedge our exposure to crude oil price fluctuations and (ii) a $0.4 million payable to Trust II for derivative contracts that we have entered into but have in turn conveyed to Trust II (although these derivatives are in a fair value asset position at quarter end, 90% of such derivative assets are due to Trust II under the terms of the conveyance). With respect to only a portion of our open derivative contracts at December 31, 2013 with certain counterparties, the forward price curve for crude oil generally exceeded the price curve that was in effect when these contracts were entered into, resulting in a derivative fair value liability. If current market prices are higher than a collar's price ceiling when the cash settlement amount is calculated, we are required to pay the contract counterparties. The ultimate settlement amounts under our derivative contracts are

unknown, however, as they are subject to continuing market risk and commodity price volatility.

(4) Asset retirement obligations represent the present value of estimated amounts expected to be incurred in the future to plug and abandon oil and gas wells, remediate oil and gas properties and dismantle their related plants and facilities.

(5) Amount shown represents the expected payment due to Alliant Energy based on projected future income tax benefits attributable to an increase in our tax bases. As a result of the Tax Separation and Indemnification Agreement signed with Alliant Energy, the increased tax bases are expected to result in increased future income tax deductions and, accordingly, may reduce income taxes otherwise payable by us. Under this agreement, we have agreed to pay Alliant Energy 90% of the future tax benefits we realize annually as a result of this step up in tax basis. In 2014, we are obligated to pay Alliant Energy the present value of the remaining tax benefits, which assumes that all such tax benefits will be realized in future years.

(6) We have three take-or-pay purchase agreements, one agreement expiring in December 2014, one agreement expiring in December 2017 and one agreement expiring in December 2029, whereby we have committed to buy certain volumes of CO2 for use in our North Ward Estes EOR project in Texas. The purchase agreements are with two different suppliers. Under the terms of the agreements, we are obligated to purchase a minimum daily volume of CO2 (as calculated on an annual basis) or else pay for any deficiencies at the price in effect when the minimum delivery was to have occurred. In addition, we have one ship-or-pay agreement expiring in December 2017, whereby we have committed to transport a minimum daily volume of CO2 via a certain pipeline or else pay for any deficiencies at a price stipulated in the contract. The CO2 volumes planned for use in the EOR project in the North Ward Estes field currently exceed the minimum daily volumes specified in all of these agreements. Therefore, we expect to avoid any payments for deficiencies. The purchasing obligations reported above represent our minimum financial commitment pursuant to the terms of these contracts. However, our actual expenditures under these contracts are expected to exceed the minimum commitments presented above.

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(7) We currently have 12 drilling rigs under long-term contract, of which six drilling rigs expire in 2014, four in 2015 and two in 2016. All of these rigs are operating in the Rocky Mountains region. As of December 31, 2013, early termination of the remaining contracts would require termination penalties of $101.1 million, which would be in lieu of paying the remaining drilling commitments of $137.9 million. No other drilling rigs working for us are currently under long-term contracts or contracts that cannot be terminated at the end of the well that is currently being drilled. Due to the short-term and indeterminate nature of the time remaining on rigs drilling on a well-by-well basis, such obligations have not been included in this table.

(8) We lease 172,400 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2018, 47,900 square feet of office space in Midland, Texas expiring in 2020 and 20,000 square feet of office space in Dickinson, North Dakota expiring in 2016. In addition, we entered into a lease for several residential apartments in Watford City and Dickinson, North Dakota under an operating lease agreement expiring in 2015.

(9) We have a contractual obligation of up to $51.4 million to fund the construction of certain facilities and field infrastructure and the drilling of forty-six CO_2 wells in our Bravo Dome field. If we fail to spend the required amounts by the dates set forth in the agreement, we will be required to pay the remaining unspent capital expenditures as liquidated damages. However, we expect to fulfill our obligations under this contract and thereby avoid any payments for deficiencies. We do not have any volumetric CO_2 delivery or supply commitments associated with this contract.

Based on current oil and natural gas prices and anticipated levels of production, we believe that the estimated net cash generated from operations, together with cash on hand and amounts available under our credit agreement, will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operations and exploration and development activities.

New Accounting Pronouncements

For further information on the effects of recently adopted accounting pronouncements and the potential effects of new accounting pronouncements, refer to the Summary of Significant Accounting Policies footnote in the notes to consolidated financial statements.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these statements requires us to make certain 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. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other factors. A summary of our significant accounting policies is detailed in Note 1 to our consolidated financial statements. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management.

Successful Efforts Accounting. We account for our oil and gas operations using the successful efforts method of accounting. Under this method, the fair value of property acquired and all costs associated with successful exploratory wells and all development wells are capitalized. Items charged to expense generally include geological and geophysical costs, costs of unsuccessful exploratory wells and oil and gas production costs. All of our properties are located within the continental United States.

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Oil and Natural Gas Reserve Quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion, impairment of our oil and natural gas properties, asset retirement obligations and our long-term Production Participation Plan liability. Proved oil and gas reserves are those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Reserve quantities and future cash flows included in this report are prepared in accordance with guidelines established by the SEC and the FASB. The accuracy of our reserve estimates 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 judgments of the persons preparing the estimates.

External petroleum engineers independently estimated all of the proved, probable and possible reserve quantities included in this annual report. In connection with our external petroleum engineers performing their independent reserve estimations, we furnish them with the following information that they review: (1) technical support data, (2) technical analysis of geologic and engineering support information, (3) economic and production data and (4) our well ownership interests. The independent petroleum engineers, Cawley, Gillespie & Associates, Inc., evaluated 100% of our estimated proved reserve quantities and their related pre-tax future net cash flows as of December 31, 2013. Estimates prepared by others may be higher or lower than our estimates. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and gas that are ultimately recovered. We continually make revisions to reserve estimates throughout the year as additional information becomes available. We make changes to depletion rates, impairment calculations (when impairment indicators arise) and our Production Participation Plan liability in the same period that changes to reserve estimates are made.

Depreciation, Depletion and Amortization. Our rate of recording DD&A is dependent upon our estimates of total proved and proved developed reserves, which estimates incorporate various assumptions and future projections. If our estimates of total proved or proved developed reserves decline, the rate at which we record DD&A expense increases, which in turn reduces our net income. Such a decline in reserves may result from lower commodity prices or other changes to reserve estimates, as discussed above, and we are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploration and development program, as well as future economic conditions.

Impairment of Oil and Gas Properties. We review the value of our oil and gas properties whenever management judges that events and circumstances indicate that the recorded carrying value of properties may not be recoverable. Impairments of producing properties are determined by comparing their future net undiscounted cash flows to their net book values at the end of each period. If their net capitalized costs exceed undiscounted future cash flows, the cost of the property is written down to “fair value,” which is determined using net discounted future cash flows from the producing property. Different pricing assumptions or discount rates could result in a different calculated impairment. In addition to proved property impairments, we provide for impairments on significant undeveloped properties when we determine that the property will not be developed or a permanent impairment in value has occurred. Individually insignificant unproved properties are amortized on a composite basis, based on past success, experience and average lease-term lives.

Asset Retirement Obligation. Our asset retirement obligations ("ARO") consist of estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage and land restoration in accordance with applicable local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The recognition of an ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free discount rate to be used; inflation rates; and future advances in technology. In periods subsequent to the initial measurement of the 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 the 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.

Production Participation Plan. We have a Production Participation Plan (the "Plan") in which all employees participate. Each year, a deemed economic interest in all oil and gas properties acquired or developed during the year is contributed to the Plan. The Compensation Committee of the Board of Directors, in its discretion for each Plan year, allocates a percentage of future net income (defined as gross revenues less production taxes, royalties and direct lease operating expenses) attributable to such properties to Plan participants. Once contributed and allocated, the interests (not legally conveyed) are fixed for each Plan year. The short-term obligation related to the Plan is included in the accrued liabilities and other line item in our consolidated balance sheets. This obligation is based on cash flows during the year and is paid annually in cash after year end. The calculation of this liability depends in part on our estimates of accrued revenues and costs as of the end of each reporting period as discussed below under "Revenue Recognition." The vested long-term obligation related to the Plan is the "Production Participation Plan liability" line item in the consolidated balance sheets. This liability is derived primarily from reserve report estimates, which as discussed above, are subject to revision as more information becomes available. Variances between estimates used to calculate liabilities related to the Plan and actual sales, costs and production data are integrated into the liability calculations in the period identified. A 10% increase to the pricing assumptions used in the measurement of this liability at December 31, 2013 would have decreased net income before taxes by $15.6 million in 2013.

Derivative Instruments and Hedging Activity. We periodically enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. We use hedging to help ensure that we have adequate cash flow to fund our capital programs and manage returns on our acquisitions and drilling programs. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While the use of these hedging arrangements limits the downside risk of adverse price movements, it may also limit future revenues from favorable price movements. We primarily utilize costless collars, which are generally placed with major financial institutions.

All derivative instruments are recorded on the consolidated balance sheet at fair value, other than the derivative instruments that meet the "normal purchase normal sales" exclusion. Changes in the derivatives' fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the fair value gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) to the extent the hedge is effective and is reclassified to the gain (loss) on hedging activities line item in our consolidated statements of income in the period that the hedged production is delivered.

We value our costless collars using industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and contractual prices for the underlying instruments, 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 values we report in our financial statements change as these estimates are revised to reflect changes in market conditions (particularly those for oil and natural gas futures) or other factors, many of which are beyond our control.

The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. We evaluate the ability of our counterparties to perform at the inception of a hedging relationship and on a periodic basis as appropriate.

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Income Taxes and Uncertain Tax Positions. We provide for income taxes in accordance with FASB ASC Topic 740, Income Taxes ("ASC 740"). We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of our deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as they relate to prevailing oil and natural gas prices).

ASC 740 requires uncertain income tax positions to meet a more-likely-than-not recognition threshold to be recognized in the financial statements. Under ASC 740, uncertain tax positions that previously failed to meet the more-likely-than-not threshold should be recognized in the first subsequent financial reporting period in which that threshold is met. Previously recognized uncertain tax positions that no longer meet the more-likely-than-not threshold should be derecognized in the first subsequent financial reporting period in which that threshold is no longer met.

We are subject to taxation in many jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions. If we ultimately determine that the payment of these liabilities will be unnecessary, we reverse the liability and recognize a tax benefit during the period in which we determine the liability no longer applies. Conversely, we record additional tax charges in a period in which we determine that a recorded tax liability is less than we expect the ultimate assessment to be.

Revenue Recognition. We predominantly derive our revenue from the sale of produced oil, NGLs and natural gas. Revenue is recorded in the month the product is delivered to the purchaser. We receive payment from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers and the price we will receive. Variances between our estimated revenue and actual payment are recorded in the month the payment is received. However, differences have been and are insignificant.

Accounting for Business Combinations. In the past, our business has grown through acquisitions, and our business strategy is to continue to pursue acquisitions as opportunities arise. 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.

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, if any, of the cost of an acquired entity over the net amounts assigned to assets acquired and liabilities assumed is recognized as goodwill. The excess, if any, of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity 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 values of estimated future cash flows, among others. Since these estimates involve the use of significant judgment, they can change as new information becomes available.

The business combinations completed during the prior three years consisted of oil and gas properties. The consideration we have paid to acquire these properties or companies 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.

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Effects of Inflation and Pricing

We experienced increased costs during 2012 and 2013 due to increased demand for oil field products and services. The oil and gas industry is very cyclical, and the demand for goods and services of oil field companies, suppliers and others associated with the industry puts extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and not adjust downward in proportion to prices. Material changes in prices also impact our 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.

Forward-Looking Statements

This report contains statements that we believe to be “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than historical facts, including, without limitation, statements regarding our future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and debt levels, and plans and objectives of management for future operations, are forward-looking statements. When used in this report, words such as we “expect,” “intend,” “plan,” “estimate,” “anticipate,” “believe” or “should” or the negative thereof or variations thereon or similar terminology are generally intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements.

These risks and uncertainties include, but are not limited to: declines in oil, NGL or natural gas prices; our level of success in exploration, development and production activities; adverse weather conditions that may negatively impact development or production activities; the timing of our exploration and development expenditures; our ability to obtain sufficient quantities of CO_2 necessary to carry out our EOR projects; inaccuracies of our reserve estimates or our assumptions underlying them; revisions to reserve estimates as a result of changes in commodity prices; impacts to financial statements as a result of impairment write-downs; risks related to our level of indebtedness and periodic redeterminations of the borrowing base under our credit agreement; our ability to generate sufficient cash flows from operations to meet the internally funded portion of our capital expenditures budget; our ability to obtain external capital to finance exploration and development operations and acquisitions; federal and state initiatives relating to the regulation of hydraulic fracturing; the potential impact of federal debt reduction initiatives and tax reform legislation being considered by the U.S. Federal Government that could have a negative effect on the oil and gas industry; our ability to identify and complete acquisitions and to successfully integrate acquired businesses; unforeseen underperformance of or liabilities associated with acquired properties; our ability to successfully complete potential asset dispositions and the risks related thereto; the impacts of hedging on our results of operations; failure of our properties to yield oil or gas in commercially viable quantities; uninsured or underinsured losses resulting from our oil and gas operations; our inability to access oil and gas markets due to market conditions or operational impediments; the impact and costs of compliance with laws and regulations governing our oil and gas operations; our ability to replace our oil and natural gas reserves; any loss of our senior management or technical personnel; competition in the oil and gas industry in the regions in which we operate; risks arising out of our hedging transactions; and other risks described under the caption “Risk Factors” in this Annual Report on Form 10-K. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this Annual Report on Form 10-K.

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Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

The price we receive for our oil and gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Crude oil and natural gas are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and gas have been volatile, and these markets will likely continue to be volatile in the future. Based on 2013 production, our income before income taxes for 2013 would have moved up or down $244.4 million for each 10% change in oil prices per Bbl, $11.4 million for each 10% change in NGL prices per Bbl and $10.9 million for each 10% change in natural gas prices per Mcf.

We periodically enter into derivative contracts to achieve a more predictable cash flow by reducing our exposure to oil and natural gas price volatility. Our derivative contracts have traditionally been costless collars, although we evaluate other forms of derivative instruments as well. Currently, we do not apply hedge accounting, and therefore all changes in commodity derivative fair values are recorded immediately to earnings. For derivative instruments that were previously designated as cash flow hedges in periods prior to April 1, 2009, the effective portion of derivative gains and losses was reclassified from accumulated other comprehensive income into earnings in the same period that the forecasted transactions effected income.

Commodity Derivative Contracts—Our outstanding hedges as of February 6, 2014 are summarized below:

Whiting Petroleum Corporation

Derivative Instrument	Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Floor/Ceiling
Three-way collars (1)	Crude Oil	01/2014	1,200,000	$71.00/$85.00/$103.56
	Crude Oil	02/2014	1,280,000	$70.94/$85.00/$103.34
	Crude Oil	03/2014	1,280,000	$70.94/$85.00/$103.34
	Crude Oil	04/2014 to 06/2014	1,280,000	$70.94/$85.00/$103.34
	Crude Oil	07/2014 to 09/2014	1,280,000	$70.94/$85.00/$103.34
	Crude Oil	10/2014 to 12/2014	1,280,000	$70.94/$85.00/$103.34

(1) A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price.

Fixed-price Natural Gas Contracts. We have various fixed-price gas sales contracts with end users for a portion of the natural gas we produce in Colorado and Utah. Our future production volumes projected to be sold under these fixed-price contracts as of February 6, 2014 are summarized below:

Commodity	Period	Average Monthly Volume (MMBtu)	Weighted Average Price Per MMBtu
Natural Gas	01/2014 to 03/2014	330,000	$5.49
Natural Gas	04/2014 to 06/2014	333,667	$5.49

Natural Gas	07/2014 to 09/2014	337,333	$5.49
Natural Gas	10/2014 to 12/2014	337,333	$5.49

Fixed-differential Crude Oil Contract. We have a fixed-differential crude oil sales contract with a purchaser for crude oil we plan to produce in Colorado from the Niobrara. The table below summarizes the future production volumes to be sold under this contract as of February 6, 2014 at a price equal to NYMEX less a fixed-differential of $4.75 per Bbl:

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Commodity	Period	Average Monthly Volume (Bbl)
Crude Oil	01/2015 to 12/2015	760,417
Crude Oil	01/2016 to 12/2016	915,000
Crude Oil	01/2017 to 12/2017	1,064,583
Crude Oil	01/2018 to 12/2018	1,216,667
Crude Oil	01/2019 to 12/2019	1,368,750

Commodity Derivatives Conveyed to Whiting USA Trust II. In connection with our conveyance on March 28, 2012 of a term net profits interest to Whiting USA Trust II ("Trust II"), the rights to any future hedge payments we make or receive on certain of our derivative contracts, representing 493 MBbl of crude oil in 2014, have been conveyed to Trust II, and therefore such payments will be included in Trust II's calculation of net proceeds. Under the terms of the aforementioned conveyance, we retain 10% of the net proceeds from the underlying properties. This results in third-party public holders of Trust II units receiving 90%, while we retain 10%, of the future economic results of such hedges. No additional hedges are allowed to be placed on Trust II assets.

The table below summarizes all of the outstanding costless collars that we entered into and then in turn conveyed, as described in the preceding paragraph, to Trust II (of which we retain 10% of the future economic results and third-party public holders of Trust II units receive 90% of the future economic results):

Conveyed to Whiting USA Trust II

Derivative Instrument	Commodity	Period	Monthly Volume (Bbl)	NYMEX Floor/Ceiling
Collars	Crude Oil	01/2014 to 03/2014	42,500	$80.00/$122.50
	Crude Oil	04/2014 to 06/2014	41,500	$80.00/$122.50
	Crude Oil	07/2014 to 09/2014	40,600	$80.00/$122.50
	Crude Oil	10/2014 to 12/2014	39,700	$80.00/$122.50

The collared hedges shown in the tables above have the effect of providing a protective floor while allowing us to share in upward pricing movements. Consequently, while these hedges are designed to decrease our exposure to price decreases, they also have the effect of limiting the benefit of price increases above the ceiling. For the crude oil collars outstanding as of December 31, 2013, a hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve as of December 31, 2013 would cause a decrease or increase, respectively, of $74.6 million in our commodity derivative (gain) loss.

Embedded Commodity Derivative Contracts—The price we pay for oil field products and services significantly impacts our profitability, reserve estimates, access to capital and future growth rate. Typically, as prices for oil and natural gas increase, so do all associated costs. In May 2011, we entered into a long-term contract to purchase CO2 from 2015 through 2029 for use in the EOR project at our North Ward Estes field in Texas. This contract contains a price adjustment clause that is linked to changes in NYMEX crude oil prices, in order to reduce our exposure to paying higher than the market rates for CO2 in a climate of declining oil prices. We have determined that the portion of this contract linked to NYMEX oil prices is not clearly and closely related to the host contract, and we have therefore bifurcated this embedded pricing feature from its host contract and reflected it at fair value in the consolidated financial statements. This embedded commodity derivative contract has not been designated as a hedge, and therefore all changes in fair value since inception have been recorded immediately to earnings. The price per Mcf of CO2 purchased under this agreement increases or decreases as the average price of NYMEX crude oil likewise increases or decreases. For this embedded commodity derivative contract, a hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve as of December 31, 2013 would cause a decrease or increase, respectively, of $13.3

million in our commodity derivative (gain) loss.

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Interest Rate Risk

Market risk is estimated as the change in fair value resulting from a hypothetical 100 basis point change in the interest rate on the outstanding balance under our credit agreement. Our credit agreement allows us to fix the interest rate for all or a portion of the principal balance for a period up to six months. To the extent that the interest rate is fixed, interest rate changes affect the instrument's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of the credit agreement that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. At December 31, 2013, we had no outstanding principal balance under our credit agreement, and therefore, a change in interest rates would not affect the amount of interest we would pay under our credit agreement. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate Senior Notes or Senior Subordinated Notes, but interest rates do affect the fair values of our Senior Notes and Senior Subordinated Notes.

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Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Whiting Petroleum Corporation
Denver, Colorado

We have audited the accompanying consolidated balance sheets of Whiting Petroleum Corporation and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, cash flows, and equity for each of the three years in the period ended December 31, 2013. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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, such consolidated financial statements present fairly, in all material respects, the financial position of Whiting Petroleum Corporation and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 27, 2014

WHITING PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS
(in thousands, except share and per share data)

	December 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 699,460	$ 44,800
Accounts receivable trade, net	341,177	318,265
Prepaid expenses and other	28,981	21,347
Total current assets	1,069,618	384,412
Property and equipment:		
Oil and gas properties, successful efforts method	10,065,150	9,211,998
Other property and equipment	206,385	141,738
Total property and equipment	10,271,535	9,353,736
Less accumulated depreciation, depletion and amortization	(2,676,490)	(2,590,203)
Total property and equipment, net	7,595,045	6,763,533
Debt issuance costs	48,530	28,748
Other long-term assets	120,277	95,726
TOTAL ASSETS	$ 8,833,470	$ 7,272,419
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable trade	$ 107,692	$ 131,370
Accrued capital expenditures	158,739	110,663
Accrued liabilities and other	214,109	170,207
Revenues and royalties payable	198,558	149,692
Taxes payable	50,052	33,283
Accrued interest	44,405	10,415
Derivative liabilities	3,482	21,955
Deferred income taxes	648	9,394
Total current liabilities	777,685	636,979
Long-term debt	2,653,834	1,800,000
Deferred income taxes	1,278,030	1,063,681
Derivative liabilities	-	1,678
Production Participation Plan liability	87,503	94,483
Asset retirement obligations	116,442	86,179
Deferred gain on sale	79,065	110,395
Other long-term liabilities	4,212	25,852
Total liabilities	4,996,771	3,819,247
Commitments and contingencies		
Equity:		
Preferred stock, $0.001 par value, 5,000,000 shares authorized; 6.25% convertible perpetual preferred stock, no shares authorized, issued or outstanding as of December 31, 2013 and 172,391 shares issued and outstanding as of December 31, 2012	-	-

Common stock, $0.001 par value, 300,000,000 shares authorized; 120,101,555 issued and 118,657,245 outstanding as of December 31, 2013 and 118,582,477 issued and 117,631,451 outstanding as of December 31, 2012		120		119
Additional paid-in capital		1,583,542		1,566,717
Accumulated other comprehensive loss		-		(1,236)
Retained earnings		2,244,905		1,879,388
Total Whiting shareholders’ equity		3,828,567		3,444,988
Noncontrolling interest		8,132		8,184
Total equity		3,836,699		3,453,172
TOTAL LIABILITIES AND EQUITY	$	8,833,470	$	7,272,419

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(in thousands, except per share data)

	Year Ended December 31, 2013	2012	2011
REVENUES AND OTHER INCOME:			
Oil, NGL and natural gas sales	$ 2,666,549	$ 2,137,714	$ 1,860,146
Gain (loss) on hedging activities	(1,958)	2,338	8,758
Amortization of deferred gain on sale	31,737	29,458	13,937
Gain on sale of properties	128,648	3,423	16,313
Interest income and other	3,409	519	468
Total revenues and other income	2,828,385	2,173,452	1,899,622
COSTS AND EXPENSES:			
Lease operating	430,221	376,424	305,487
Production taxes	225,403	171,625	139,190
Depreciation, depletion and amortization	891,516	684,724	468,203
Exploration and impairment	453,210	166,972	84,644
General and administrative	137,994	108,573	84,985
Interest expense	112,936	75,210	62,516
Loss on early extinguishment of debt	4,412	-	-
Change in Production Participation Plan liability	(6,980)	13,824	(865)
Commodity derivative (gain) loss, net	7,802	(85,911)	(24,857)
Total costs and expenses	2,256,514	1,511,441	1,119,303
INCOME BEFORE INCOME TAXES	571,871	662,011	780,319
INCOME TAX EXPENSE (BENEFIT):			
Current	986	(669)	3,853
Deferred	204,882	248,581	284,838
Total income tax expense	205,868	247,912	288,691
NET INCOME	366,003	414,099	491,628
Net loss attributable to noncontrolling interest	52	90	59
NET INCOME AVAILABLE TO SHAREHOLDERS	366,055	414,189	491,687
Preferred stock dividends	(538)	(1,077)	(1,077)
	$ 365,517	$ 413,112	$ 490,610

NET INCOME AVAILABLE TO COMMON SHAREHOLDERS						
EARNINGS PER COMMON SHARE:						
Basic	$	3.09	$	3.51	$	4.18
Diluted	$	3.06	$	3.48	$	4.14
WEIGHTED AVERAGE SHARES OUTSTANDING:						
Basic		118,260		117,601		117,345
Diluted		119,588		119,028		118,668

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands)

	Year Ended December 31, 2013	2012	2011
NET INCOME	$ 366,003	$ 414,099	$ 491,628
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:			
OCI amortization on de-designated hedges (1)(2)	1,236	(1,476)	(5,528)
Total other comprehensive income (loss), net of tax	1,236	(1,476)	(5,528)
COMPREHENSIVE INCOME	367,239	412,623	486,100
Comprehensive loss attributable to noncontrolling interest	52	90	59
COMPREHENSIVE INCOME ATTRIBUTABLE TO WHITING	$ 367,291	$ 412,713	$ 486,159

(1) Presented net of income tax expense of $722 for the year ended December 31, 2013 and income tax benefits of $862 and $3,230 for the years ended December 31, 2012 and 2011, respectively.
(2) These gain (loss) amounts on de-designated hedges are reclassified from accumulated other comprehensive income (“AOCI”) to gain (loss) on hedging activities in the consolidated statements of income.

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31, 2013	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 366,003	$ 414,099	$ 491,628
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	891,516	684,724	468,203
Deferred income tax expense	204,882	248,581	284,838
Amortization of debt issuance costs and debt premium	12,405	9,518	8,682
Stock-based compensation	22,436	18,190	13,509
Amortization of deferred gain on sale	(31,737)	(29,458)	(13,937)
Gain on sale of properties	(128,648)	(3,423)	(16,313)
Undeveloped leasehold and oil and gas property impairments	358,455	107,855	38,783
Exploratory dry hole costs	28,725	18,428	4,924
Loss on early extinguishment of debt	4,412	-	-
Change in Production Participation Plan liability	(6,980)	13,824	(865)
Non-cash portion of derivative (gains) and losses	(20,830)	(115,733)	(63,093)
Other, net	(16,118)	(18,708)	(13,512)
Changes in current assets and liabilities:			
Accounts receivable trade	(22,912)	(55,750)	(62,802)
Prepaid expenses and other	(15,981)	2,535	(3,771)
Accounts payable trade and accrued liabilities	33,360	58,647	33,135
Revenues and royalties payable	48,988	45,798	21,770
Taxes payable	16,769	2,088	904
Net cash provided by operating activities	1,744,745	1,401,215	1,192,083
CASH FLOWS FROM INVESTING ACTIVITIES:			
Drilling and development capital expenditures	(2,349,819)	(2,050,029)	(1,554,271)
Acquisition of oil and gas properties	(422,923)	(125,282)	(193,809)
Other property and equipment	(45,304)	3,852	(56,232)
Proceeds from sale of oil and gas properties	968,606	69,190	69,276
Net proceeds from sale of 18,400,000 units in Whiting USA Trust II	-	322,257	-
Issuance of note receivable	(10,530)	(306)	(25,000)
Cash paid for investing derivatives	(44,900)	-	-
Cash settlements received on investing derivatives	2,371	-	-

Net cash used in investing activities	(1,902,499)	(1,780,318)	(1,760,036)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Issuance of 5% Senior Notes due 2019	1,100,000	-	-
Issuance of 5.75% Senior Notes due 2021	1,204,000	-	-
Redemption of 7% Senior Subordinated Notes due 2014	(253,988)	-	-
Long-term borrowings under credit agreement	1,860,000	2,340,000	1,760,000
Repayments of long-term borrowings under credit agreement	(3,060,000)	(1,920,000)	(1,180,000)
Debt issuance costs	(29,690)	(2,807)	(5,691)
Restricted stock used for tax withholdings	(5,611)	(5,695)	(9,049)
Repayments to Alliant Energy Corporation	(1,759)	(2,329)	(1,871)
Preferred stock dividends paid	(538)	(1,077)	(1,077)
Contributions from noncontrolling interest	-	-	2,500
Net cash provided by financing activities	$ 812,414	$ 408,092	$ 564,812

See notes to consolidated financial statements.

(Continued)

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WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31, 2013	2012	2011
NET CHANGE IN CASH AND CASH EQUIVALENTS	$ 654,660	$ 28,989	$ (3,141)
CASH AND CASH EQUIVALENTS:			
Beginning of period	44,800	15,811	18,952
End of period	$ 699,460	$ 44,800	$ 15,811
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Income taxes paid (refunded), net	$ 3,681	$ (268)	$ 4,065
Interest paid, net of amounts capitalized	$ 66,541	$ 68,005	$ 53,761
NONCASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$ 158,739	$ 110,663	$ 142,827
NONCASH FINANCING ACTIVITIES:			
Contributions from noncontrolling interest	$ -	$ -	$ 5,833

See notes to consolidated financial statements.

(Concluded)

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WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY
(in thousands)

	Preferred Stock		Common Stock		Additional Paid-in	Accumulated Other Comprehensive Income	Retained	Total Whiting Shareholders'	Noncontrolling	Total
	Shares	Amount	Shares	Amount	Capital	(Loss)	Earnings	Equity	Interest	Equity
BALANCES-January 1, 2011	173	$-	117,968	$59	$1,549,822	$5,768	$975,666	$2,531,315	$-	$2,531,315
Net income (loss)	-	-	-	-	-		491,687	491,687	(59)	491,628
Other comprehensive income	-	-	-	-	-	(5,528)	-	(5,528)	-	(5,528
Conversion of preferred stock to common	(1)	-	1	-	-	-	-	-	-	-–
Two-for-one stock split	-	-	-	59	(59)	-	-	-	-	-
Contributions from noncontrolling interest	-	-	-	-	-	-	-	-	8,333	8,333
Restricted stock issued	-	-	304	-	-	-	-	-	-	-
Restricted stock forfeited	-	-	(20)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(148)	-	(9,049)	-	-	(9,049)	-	(9,049
Stock-based compensation	-	-	-	-	13,509	-	-	13,509	-	13,509
Preferred dividends paid	-	-	-	-	-	-	(1,077)	(1,077)	-	(1,077
BALANCES-December 31, 2011	172	-	118,105	118	1,554,223	240	1,466,276	3,020,857	8,274	3,029,131
Net income (loss)	-	-	-	-	-	-	414,189	414,189	(90)	414,099
Other comprehensive income	-	-	-	-	-	(1,476)	-	(1,476)	-	(1,476
Restricted stock issued	-	-	592	1	(1)	-	-	-	-	-
Restricted stock forfeited	-	-	(9)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(106)	-	(5,695)	-	-	(5,695)	-	(5,695
Stock-based compensation	-	-	-	-	18,190	-	-	18,190	-	18,190
Preferred dividends paid	-	-	-	-	-	-	(1,077)	(1,077)	-	(1,077
BALANCES-December 31, 2012	172	-	118,582	119	1,566,717	(1,236)	1,879,388	3,444,988	8,184	3,453,172
Net income (loss)	-	-	-	-	-	-	366,055	366,055	(52)	366,003
Other comprehensive loss	-	-	-	-	-	1,236	-	1,236	-	1,236
Conversion of preferred stock to common	(172)	-	794	1	-	-	-	1	-	1

Restricted stock issued	-	-	941	-	-	-	-	-	-	-
Restricted stock forfeited	-	-	(100)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(115)	-	(5,611)	-	-	(5,611)	-	(5,611
Stock-based compensation	-	-	-	-	22,436	-	-	22,436	-	22,436
Preferred dividends paid	-	-	-	-	-	-	(538)	(538)	-	(538
BALANCES-December 31, 2013	-	$-	120,102	$120	$1,583,542	$-	$2,244,905	$3,828,567	$8,132	$3,836,699

See notes to consolidated financial statements.

WHITING PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations—Whiting Petroleum Corporation, a Delaware corporation, is an independent oil and gas company that explores for, develops, acquires and produces crude oil, NGLs and natural gas primarily in the Rocky Mountains and Permian Basin regions of the United States. Unless otherwise specified or the context otherwise requires, all references in these notes to “Whiting” or the “Company” are to Whiting Petroleum Corporation and its consolidated subsidiaries.

Basis of Presentation of Consolidated Financial Statements—The consolidated financial statements include the accounts of Whiting Petroleum Corporation, its consolidated subsidiaries and Whiting’s pro rata share of the accounts of Whiting USA Trust I (“Trust I”) pursuant to Whiting’s 15.8% ownership interest in Trust I. Investments in entities which give Whiting significant influence, but not control, over the investee are accounted for using the equity method. Under the equity method, investments are stated at cost plus the Company’s equity in undistributed earnings and losses. All intercompany balances and transactions have been eliminated upon consolidation.

Use of Estimates—The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the 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. Items subject to such estimates and assumptions include (1) oil and natural gas reserves; (2) cash flow estimates used in impairment tests of long-lived assets; (3) depreciation, depletion and amortization; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations; (6) income taxes; (7) Production Participation Plan and other accrued liabilities; (8) valuation of derivative instruments; and (9) accrued revenue and related receivables. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Cash and Cash Equivalents—Cash equivalents consist of demand deposits and highly liquid investments which have an original maturity of three months or less.

Accounts Receivable Trade—Whiting’s accounts receivable trade consist mainly of receivables from oil and gas purchasers and joint interest owners on properties the Company operates. For receivables from joint interest owners, Whiting typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Generally, the Company’s oil and gas receivables are collected within two months, and to date, the Company has had minimal bad debts.

The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectability. At December 31, 2013 and 2012, the Company had an allowance for doubtful accounts of $4.2 million and $3.9 million, respectively.

Inventories—Materials and supplies inventories consist primarily of tubular goods and production equipment, carried at weighted-average cost. Materials and supplies are included in other property and equipment. Crude oil in tanks inventory is carried at the lower of the estimated cost to produce or market value and is included in prepaid expenses and other.

Oil and Gas Properties

Proved. The Company follows the successful efforts method of accounting for its oil and gas properties. Under this method of accounting, all property acquisition costs and development costs are capitalized when incurred and depleted on a units-of-production basis over the remaining life of proved reserves and proved developed reserves, respectively. Costs of drilling exploratory wells are initially capitalized but are charged to expense if the well is determined to be unsuccessful.

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The Company assesses its proved oil and gas properties for impairment whenever events or circumstances indicate that the carrying value of the assets may not be recoverable. The impairment test compares undiscounted future net cash flows to the assets' net book value. If the net capitalized costs exceed future net cash flows, then the cost of the property is written down to fair value. Fair value for oil and gas properties is generally determined based on discounted future net cash flows. Impairment expense for proved properties is reported in exploration and impairment expense.

Net carrying values of retired, sold or abandoned properties that constitute less than a complete unit of depreciable property are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized in income. Gains or losses from the disposal of complete units of depreciable property are recognized to earnings.

Interest cost is capitalized as a component of property cost for development projects that require greater than six months to be readied for their intended use. During 2013, 2012 and 2011, the Company capitalized interest of $1.5 million, $2.7 million and $3.6 million, respectively.

Unproved. Unproved properties consist of costs to acquire undeveloped leases as well as costs to acquire unproved reserves. Undeveloped lease costs and unproved reserve acquisitions are capitalized, and individually insignificant unproved properties are amortized on a composite basis, based on past success, past experience and average lease-term lives. The Company evaluates significant unproved properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. When successful wells are drilled on undeveloped leaseholds, unproved property costs are reclassified to proved properties and depleted on a unit-of-production basis. Impairment expense for unproved properties is reported in exploration and impairment expense.

Exploratory. Geological and geophysical costs, including exploratory seismic studies, and the costs of carrying and retaining unproved acreage are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between development costs and exploration expense.

Costs of drilling exploratory wells are initially capitalized, pending determination of whether the well has found proved reserves. If an exploratory well has not found proved reserves, the costs of drilling the well and other associated costs are charged to expense. Cost incurred for exploratory wells that find reserves, which cannot yet be classified as proved, continue to be capitalized if (a) the well has found a sufficient quantity of reserves to justify completion as a producing well, and (b) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met, or if the Company obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well costs, net of any salvage value, are expensed.

Enhanced recovery activities. The Company carries out tertiary recovery methods on certain of its oil and gas properties in order to recover additional hydrocarbons that are not recoverable from primary or secondary recovery methods. Acquisition costs of tertiary injectants, such as purchased CO2, for enhanced oil recovery ("EOR") activities that are used during a project's pilot phase, or prior to a project's technical and economic viability (i.e. prior to the recognition of proved tertiary recovery reserves) are expensed as incurred. After a project has been determined to be technically feasible and economically viable, all acquisition costs of tertiary injectants are capitalized as development costs and depleted, as they are incurred solely for obtaining access to reserves not otherwise recoverable and have future economic benefits over the life of the project. As CO2 is recovered together with oil and gas production, it is extracted and re-injected, and all the associated CO_2 recycling costs are expensed as incurred. Likewise costs incurred to maintain reservoir pressure are also expensed.

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Other Property and Equipment—Other property and equipment consists of (i) materials and supplies inventories, (ii) leasehold costs and development costs of our CO2 source properties and (iii) other property and equipment including an oil pipeline, furniture and fixtures, buildings, leasehold improvements and automobiles, which are stated at cost and depreciated using the straight-line method over their estimated useful lives ranging from 4 to 33 years. In July 2013, the Company sold the oil pipeline, as discussed in the Acquisitions and Divestitures footnote.

Debt Issuance Costs—Debt issuance costs related to the Company's Senior Notes and Senior Subordinated Notes are amortized to interest expense using the effective interest method over the term of the related debt. Debt issuance costs related to the credit facility are amortized to interest expense on a straight-line basis over the borrowing term.

Asset Retirement Obligations and Environmental Costs—Asset retirement obligations relate to future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage and returning such land to its original condition. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred (typically when a well is completed or acquired or an asset is installed at the production location), and the cost of such liability increases the carrying amount of the related long-lived asset by the same amount. The liability is accreted each period through charges to depreciation, depletion and amortization expense, and the capitalized cost is depleted on a units-of-production basis over the proved developed reserves of the related asset. Revisions to estimated retirement obligations result in adjustments to the related capitalized asset and corresponding liability.

Liabilities for environmental costs are recorded on an undiscounted basis when it is probable that obligations have been incurred and the amounts can be reasonably estimated. These liabilities are not reduced by possible recoveries from third parties.

Derivative Instruments—The Company enters into derivative contracts, primarily costless collars, to manage its exposure to commodity price risk. All derivative instruments, other than those that meet the "normal purchase normal sales" exclusion, are recorded on the balance sheet as either an asset or liability measured at fair value. Gains and losses from changes in the fair value of derivative instruments are recognized immediately in earnings, unless the derivative meets specific hedge accounting criteria, and the derivative has been designated as a hedge. Effective April 1, 2009, however, the Company elected to discontinue all hedge accounting prospectively. Cash flows from derivatives used to manage commodity price risk are classified in operating activities along with the cash flows of the underlying hedged transactions. The Company does not enter into derivative instruments for speculative or trading purposes.

For derivatives qualifying as hedges of future cash flows prior to April 1, 2009, the effective portion of any changes in fair value was recognized in accumulated other comprehensive income (loss) and was reclassified to net income when the underlying forecasted transaction occurred. Any ineffective portion of such hedges was recognized in commodity derivative (gain) loss, net as it occurred. For discontinued cash flow hedges, prospective changes in the fair value of the derivative are recognized in earnings. The accumulated gain or loss recognized in accumulated other comprehensive income (loss) at the time a hedge is discontinued continues to be deferred until the original forecasted transaction occurs. However, if it is determined that the likelihood of the original forecasted transaction occurring is no longer probable, the entire accumulated gain or loss recognized in accumulated other comprehensive income (loss) is immediately reclassified into earnings. As of December 31, 2013, all amounts related to de-designated cash flow hedges had been reclassified into earnings.

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Deferred Gain on Sale—The deferred gain on sale relates to the sale of 11,677,500 Trust I units and 18,400,000 Whiting USA Trust II ("Trust II") units, and is amortized to income based on the units-of-production method.

Revenue Recognition—Oil and gas revenues are recognized when production volumes are sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred, persuasive evidence of a sales arrangement exists and collectability of the revenue is probable. Revenues from the production of gas properties in which the Company has an interest with other producers are recognized on the basis of the Company's net working interest (entitlement method). Net deliveries in excess of entitled amounts are recorded as liabilities, while net under deliveries are reflected as receivables. Gas imbalance receivables or payables are valued at the lowest of (i) the current market price, (ii) the price in effect at the time of production, or (iii) the contract price, if a contract is in hand. As of December 31, 2013 and 2012, the Company was in a net under (over) produced imbalance position of (110,798) Mcf and (53,536) Mcf, respectively.

Taxes collected and remitted to governmental agencies on behalf of customers are not included in revenues or costs and expenses.

General and Administrative Expenses—General and administrative expenses are reported net of reimbursements of overhead costs that are allocated to working interest owners in the oil and gas properties operated by Whiting.

Acquisition Costs—Acquisition related expenses, which consist of external costs directly related to the Company's acquisitions, such as advisory, legal, accounting, valuation and other professional fees are expensed as incurred.

Maintenance and Repairs—Maintenance and repair costs which do not extend the useful lives of property and equipment are charged to expense as incurred. Major replacements, renewals and betterments are capitalized.

Income Taxes—Income taxes are recognized based on earnings reported for tax return purposes in addition to a provision for deferred income taxes. Deferred income taxes are accounted for using the liability method. Under this method, deferred tax assets and liabilities are determined by applying the enacted statutory tax rates in effect at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the Company's financial statements. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance for deferred tax assets is established when it is more likely than not that some portion of the benefit from deferred tax assets will not be realized. The Company's uncertain tax positions must meet a more-likely-than-not realization threshold to be recognized, and any potential accrued interest and penalties related to unrecognized tax benefits are recognized within income tax expense.

Earnings Per Share—Basic earnings per common share is calculated by dividing net income available to common shareholders by the weighted average number of common shares outstanding during each period. Diluted earnings per common share is calculated by dividing adjusted net income available to common shareholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculations consist of unvested restricted stock awards and outstanding stock options using the treasury method, as well as convertible perpetual preferred stock using the if-converted method. In the computation of diluted earnings per share, excess tax benefits that would be created upon the assumed vesting of unvested restricted shares or the assumed exercise of stock options (i.e. hypothetical excess tax benefits) are included in the assumed proceeds component of the treasury share method to the extent that such excess tax benefits are more likely than not to be realized. When a loss from continuing operations exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share.

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Industry Segment and Geographic Information—The Company has evaluated how it is organized and managed and has identified only one operating segment, which is the exploration and production of crude oil, NGLs and natural gas. The Company considers its gathering, processing and marketing functions as ancillary to its oil and gas producing activities. All of the Company's operations and assets are located in the United States, and substantially all of its revenues are attributable to United States customers.

Fair Value of Financial Instruments—The Company has included fair value information in these notes when the fair value of our financial instruments is materially different from their book value. Cash and cash equivalents, accounts receivable and payable are carried at cost, which approximates their fair value because of the short-term maturity of these instruments. The Company's credit agreement has a recorded value that approximates its fair value since its variable interest rate is tied to current market rates. The Company's Senior Notes and Senior Subordinated Notes are recorded at cost, and the fair values of these instruments are included in the Long-Term Debt footnote. The Company's derivative financial instruments are recorded at fair value and include a measure of the Company's own nonperformance risk or that of its counterparties as appropriate.

Concentration of Credit Risk—Whiting is exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy related industries. The creditworthiness of customers and other counterparties is subject to continuing review. The following table presents the percentages by purchaser that accounted for 10% or more of the Company's total oil, NGL and natural gas sales for the years ended December 31, 2013, 2012 and 2011:

	2013	2012	2011
Plains Marketing LP	21%	20%	27%
Shell Trading US	14%	14%	13%
Eighty Eight Oil Company	11%	11%	8%
Bridger Trading LLC	8%	11%	6%

Commodity derivative contracts held by the Company are with eight counterparties, all of which are participants in Whiting's credit facility as well, and all of which have investment-grade ratings from Moody's and Standard & Poor. As of December 31, 2013, outstanding derivative contracts with JP Morgan Chase Bank, N.A., Canadian Imperial Bank of Commerce, The Bank of Nova Scotia and Bank of America Merrill Lynch represented 29%, 21%, 12% and 12%, respectively, of total crude oil volumes hedged.

Reclassifications—Certain prior period balances in the consolidated balance sheets have been reclassified to conform to the current year presentation. Such reclassifications had no impact on net income, cash flows or shareholders' equity previously reported.

Adopted and Recently Issued Accounting Pronouncements—In May 2011, the FASB issued Accounting Standards Update No. 2011-04, Fair Value Measurement: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs ("ASU 2011-04"), which provides amendments to FASB ASC Topic 820, Fair Value Measurement. The objective of ASU 2011-04 is to create common fair value measurement and disclosure requirements between GAAP and International Financial Reporting Standards ("IFRS"). The amendments clarify existing fair value measurement and disclosure requirements and make changes to particular principles or requirements for measuring or disclosing information about fair value measurements. ASU 2011-04 was effective for interim and annual reporting periods beginning after December 15, 2011. The Company adopted this standard effective January 1, 2012, which did not have an impact on the Company's consolidated financial statements other than additional disclosures.

In June 2011, the FASB issued Accounting Standards Update No. 2011-05, Comprehensive Income: Presentation of Comprehensive Income (“ASU 2011-05”), which provides amendments to FASB ASC Topic 220, Comprehensive Income. The objective of ASU 2011-05 is to require an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. ASU 2011-05 eliminates the option to present the components of other comprehensive income as part of the statement of equity. ASU 2011-05 is effective for interim and annual periods beginning after December 15, 2011 and is to be applied retrospectively. In December 2011, the FASB issued Accounting Standards Update No. 2011-12, Comprehensive Income: Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05 (“ASU 2011-12”), which deferred the effective date of changes in ASU 2011-05 that relate to the presentation of reclassification adjustments out of accumulated other comprehensive income. The amendments in this update are effective at the same time as the amendments in ASU 2011-05. The Company adopted the provisions of ASU 2011-05 and 2011-12 effective January 1, 2012, which did not have an impact on its consolidated financial statements other than requiring the Company to present its statements of comprehensive income separately from its statements of equity, as these statements were formerly presented on a combined basis.

In December 2011, the FASB issued Accounting Standards Update No. 2011-11, Balance Sheet: Disclosures about Offsetting Assets and Liabilities (“ASU 2011-11”). 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. In January 2013, the FASB issued Accounting Standards Update No. 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities (“ASU 2013-01”), which clarifies that the scope of ASU 2011-11 applies to derivatives accounted for in accordance with FASB ASC Topic 815, Derivatives and Hedging, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities lending transactions that are either offset in accordance with FASB ASC Section 210-20-45 or Section 815-10-45 or subject to an enforceable master netting arrangement or similar agreement. ASU 2011-11 and ASU 2013-01 are effective for interim and annual reporting periods beginning on or after January 1, 2013 and should be applied retrospectively. The Company adopted ASU 2011-11 and ASU 2013-01 effective January 1, 2013, which did not have an impact on the Company’s consolidated financial statements other than additional disclosures.

In July 2012, the FASB issued Accounting Standards Update No. 2012-02, Intangibles – Goodwill and Other – Testing Indefinite-Lived Intangible Assets for Impairment (“ASU 2012-02”). The objective of ASU 2012-02 is to reduce the cost and complexity of performing an impairment test for indefinite-lived intangible assets by permitting an entity first to assess qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired, as a basis for determining whether it is necessary to perform a quantitative impairment test. ASU 2012-02 is effective for interim and annual reporting periods beginning after September 15, 2012. The Company adopted ASU 2012-02 effective January 1, 2013, which did not have an impact on the Company’s consolidated financial statements.

In February 2013, the FASB issued Accounting Standards Update No. 2013-02, Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income (“ASU 2013-02”). The objective of ASU 2013-02 is to improve the reporting of reclassifications out of AOCI by requiring an entity to report the effect of significant reclassifications out of AOCI on the respective line items in net income if the amount being reclassified is required under GAAP to be reclassified in its entirety to net income. For other amounts that are not required under GAAP to be reclassified in their entirety to net income in the same reporting period, an entity is required to cross-reference other disclosures required under GAAP that provide additional detail about those amounts. ASU 2013-02 is effective for interim and annual reporting periods beginning after December 15, 2012. The Company adopted ASU 2013-02 effective January 1, 2013, which did not have a significant impact on the Company’s consolidated financial statements.

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In February 2013, the FASB issued Accounting Standards Update No. 2013-04, Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date ("ASU 2013-04"). The objective of ASU 2013-04 is to provide guidance for the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date. ASU 2013-04 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

In July 2013, the FASB issued Accounting Standards Update No. 2013-11, Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists ("ASU 2013-11"). The objective of ASU 2013-11 is to provide guidance on financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. ASU 2013-11 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The adoption of this standard will not have an impact on the Company's consolidated financial statements, other than insignificant balance sheet reclassifications.

2. OIL AND GAS PROPERTIES

Net capitalized costs related to the Company's oil and gas producing activities at December 31, 2013 and 2012 are as follows (in thousands):

	December 31,	
	2013	2012
Proved leasehold costs	$ 1,633,495	$ 2,119,541
Unproved leasehold costs	372,298	362,483
Costs of completed wells and facilities	7,563,350	6,369,170
Wells and facilities in progress	496,007	360,804
Total oil and gas properties, successful efforts method	10,065,150	9,211,998
Accumulated depletion	(2,645,841)	(2,564,081)
Oil and gas properties, net	$ 7,419,309	$ 6,647,917

3. ACQUISITIONS AND DIVESTITURES

2013 Acquisitions

On September 20, 2013, the Company completed the acquisition of approximately 39,300 gross (17,300 net) acres, including interests in 121 producing oil and gas wells and undeveloped acreage, in the Williston Basin located in Williams and McKenzie counties of North Dakota and Roosevelt and Richland counties of Montana for an aggregate unadjusted purchase price of $260.0 million. Revenue and earnings from these properties since the September 20, 2013 acquisition date, which are included in the consolidated statements of income for the year ended December 31, 2013, are not material. Disclosures of pro forma revenues and net income for the acquisition of these wells are not material and have not been presented accordingly.

The acquisition was recorded using the purchase method of accounting. The following table summarizes the preliminary allocation of the $258.9 million adjusted purchase price (which is still subject to post-closing adjustments) to the tangible assets acquired and liabilities assumed in this acquisition oil and gas properties. As the purchase price is further adjusted for post-close adjustments and as oil and gas property valuations are completed, the final purchase price allocation may result in a different allocation to the tangible assets from that which is presented in the table below (in thousands):

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Purchase price	$258,892
Allocation of purchase price:	
Proved properties	$232,187
Unproved properties	27,335
Oil in tank inventory	692
Accounts receivable	578
Asset retirement obligations	(1,900)
Total	$258,892

2013 Divestitures

On October 31, 2013, the Company completed the sale of approximately 45,000 gross (32,200 net) acres, including its interests in certain producing oil and gas wells and undeveloped acreage, in its Big Tex prospect located in the Delaware Basin for a cash purchase price of $152.0 million (subject to post-closing adjustments), resulting in a pre-tax gain on sale of $13.0 million. Of the total net acres sold, approximately 30,800 net acres are located in Pecos County, Texas, and approximately 1,400 net acres are located in Reeves County, Texas.

On July 15, 2013, the Company completed the sale of its interests in certain oil and gas producing properties located in its enhanced oil recovery projects in the Postle and Northeast Hardesty fields in Texas County, Oklahoma, including the related Dry Trail plant gathering and processing facility, oil delivery pipeline, its entire 60% interest in the Transpetco CO2 pipeline, crude oil swap contracts and certain other related assets and liabilities (collectively the "Postle Properties") for a cash purchase price of $809.7 million after selling costs and post-closing adjustments, resulting in a pre-tax gain on sale of $109.7 million. The Company used the net proceeds from this sale to repay a portion of the debt outstanding under its credit agreement.

Upon closing of the transaction, the following crude oil swaps and any of their related cash settlements as of that date were transferred to the buyer of the Postle Properties:

Period	Contracted Crude Oil Volumes (Bbl)	NYMEX Price for Crude Oil (per Bbl)
Apr – Dec 2013	1,677,500	$98.50
Jan – Dec 2014	2,007,500	$94.75
Jan – Dec 2015	1,825,000	$94.75
Jan – Mar 2016	400,400	$93.50
Total	5,910,400	

2012 Acquisitions

On March 22, 2012, the Company completed the acquisition of approximately 13,300 net undeveloped acres in the Missouri Breaks field in Richland County, Montana for $33.3 million.

2012 Divestitures

On May 18, 2012, the Company sold a 50% ownership interest in its Belfield gas processing plant, natural gas gathering system, oil gathering system and related facilities located in Stark County, North Dakota for total cash proceeds of $66.2 million. Whiting used the net proceeds from the sale to repay a portion of the debt outstanding under its credit agreement.

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On March 28, 2012, the Company completed an initial public offering of units of beneficial interest in Trust II, selling 18,400,000 Trust II units at $20.00 per unit, which generated net proceeds of $322.3 million after underwriters' fees, offering expenses and post-close adjustments. The Company used the net offering proceeds to repay a portion of the debt outstanding under its credit agreement. The net proceeds from the sale of Trust II units to the public resulted in a deferred gain on sale of $128.2 million. Immediately prior to the closing of the offering, Whiting conveyed a term net profits interest in certain of its oil and gas properties to Trust II in exchange for 100% of the trust's units issued, or 18,400,000 units.

The net profits interest entitles Trust II to receive 90% of the net proceeds from the sale of oil and natural gas production from the underlying properties. The net profits interest will terminate on the later to occur of (1) December 31, 2021, or (2) the time when 11.79 MMBOE have been produced from the underlying properties and sold. This is the equivalent of 10.61 MMBOE in respect of Trust II's right to receive 90% of the net proceeds from such reserves pursuant to the net profits interest.

2011 Acquisitions

On July 28, 2011, the Company completed the acquisition of approximately 23,400 net acres and one well in the Missouri Breaks field in Richland County, Montana for an unadjusted purchase price of $46.9 million. Disclosures of pro forma revenues and net income for the acquisition of this one well are not material and have not been presented accordingly.

On March 18, 2011, Whiting and an unrelated third party formed Sustainable Water Resources, LLC ("SWR") to develop a water project in the state of Colorado. The Company contributed $25.0 million for a 75% interest in SWR, and the 25% noncontrolling interest in SWR was ascribed a fair value of $8.3 million, which consisted of $2.5 million in cash contributions, as well as $5.8 million in intangible and fixed assets contributed to the joint venture.

On February 15, 2011, the Company completed the acquisition of 6,000 net undeveloped acres and additional working interests in the Pronghorn field in the Billings and Stark counties of North Dakota, for an aggregate purchase price of $40.0 million.

2011 Divestiture

On September 29, 2011, Whiting sold its interest in several non-core oil and gas producing properties located in the Karnes, Live Oak and DeWitt counties of Texas for total cash proceeds of $64.8 million, resulting in a pre-tax gain on sale of $12.3 million. Whiting used the net proceeds from the property sale to repay a portion of the debt outstanding under its credit agreement.

4. LONG-TERM DEBT

Long-term debt consisted of the following at December 31, 2013 and 2012 (in thousands):

	December 31, 2013	December 31, 2012
Credit agreement	$ -	$ 1,200,000
7% Senior Subordinated Notes due 2014	-	250,000
6.5% Senior Subordinated Notes due 2018	350,000	350,000
5% Senior Notes due 2019	1,100,000	-
5.75% Senior Notes due 2021, including unamortized debt premium of $3,834	1,203,834	-

Total debt	$ 2,653,834	$ 1,800,000

The following table shows five succeeding fiscal years of scheduled maturities for the Company's long-term debt as of December 31, 2013 (in thousands):

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	2014	2015	2016	2017	2018
Long-term debt	$ -	$ -	$ -	$ -	$ 350,000

Credit Agreement—Whiting Oil and Gas Corporation ("Whiting Oil and Gas"), the Company's wholly-owned subsidiary, has a credit agreement with a syndicate of banks that as of December 31, 2013 had a borrowing base of $2.8 billion, of which $1.2 billion has been committed by lenders and is available for borrowing. The Company may increase the maximum aggregate amount of commitments under the credit agreement up to the $2.8 billion borrowing base if certain conditions are satisfied, including the consent of lenders participating in the increase. As of December 31, 2013, the Company had $1,197.0 million of available borrowing capacity, which was net of $3.0 million in letters of credit with no borrowings outstanding.

The credit agreement provides for interest only payments until April 2016, when the agreement expires and all outstanding borrowings are due. The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of the Company's proved reserves that have been mortgaged to such lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. A portion of the revolving credit facility in an aggregate amount not to exceed $50.0 million may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of the Company. As of December 31, 2013, $47.0 million was available for additional letters of credit under the agreement.

Interest accrues at the Company's option at either (i) a base rate for a base rate loan plus the margin in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.50% or an adjusted LIBOR rate plus 1.00%, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus the margin in the table below. Additionally, the Company also incurs commitment fees as set forth in the table below on the unused portion of the lesser of the aggregate commitments of the lenders or the borrowing base, and which are included as a component of interest expense. The Company's credit agreement has a recorded value that approximates its fair value since its variable interest rate is tied to current market rates.

Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans	Commitment Fee
Less than 0.25 to 1.0	0.50%	1.50%	0.375%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	0.75%	1.75%	0.375%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.00%	2.00%	0.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.25%	2.25%	0.50%
Greater than or equal to 0.90 to 1.0	1.50%	2.50%	0.50%

The credit agreement contains restrictive covenants that may limit the Company's ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of its lenders. Except for limited exceptions, the credit agreement also restricts the Company's ability to make any dividend payments or distributions on its common stock. These restrictions apply to all of the net assets of Whiting Oil and Gas. As of December 31, 2013, total restricted net assets were $4,070.4 million, and the amount of retained earnings free from restrictions was $23.0 million. The credit agreement requires the Company, as of the last day of any quarter, (i) to not exceed a total debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 4.0 to 1.0 and (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0. The Company was in compliance with its covenants under the credit agreement as of December 31, 2013.

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The obligations of Whiting Oil and Gas under the credit agreement are secured by a first lien on substantially all of Whiting Oil and Gas' properties included in the borrowing base for the credit agreement. The Company has guaranteed the obligations of Whiting Oil and Gas under the credit agreement and has pledged the stock of Whiting Oil and Gas as security for its guarantee.

Senior Notes and Senior Subordinated Notes—In September 2010, the Company issued at par $350.0 million of 6.5% Senior Subordinated Notes due October 2018. The estimated fair value of these notes was $371.0 million as of December 31, 2013, based on quoted market prices for these debt securities, and such fair value is therefore designated as Level 1 within the valuation hierarchy.

Issuance of Senior Notes. In September 2013, the Company issued at par $1,100.0 million of 5% Senior Notes due March 2019 and $800.0 million of 5.75% Senior Notes due March 2021, and issued at 101% of par an additional $400.0 million of 5.75% Senior Notes due March 2021 (collectively, the "Senior Notes"). The Company used the net proceeds from these issuances to repay all of the debt outstanding under its credit agreement, to fund its $260.0 million acquisition of Williston Basin assets discussed in the Acquisitions and Divestitures footnote and to redeem all $250.0 million of its 7% Senior Subordinated Notes due February 2014 (the "2014 Notes"). The Company plans to use the remainder of the net proceeds for general corporate purposes including capital expenditures. The estimated fair values of the 2019 notes and the 2021 notes were $1,122.0 million and $1,260.0 million, respectively, as of December 31, 2013, based on quoted market prices for these debt securities, and such fair values are therefore designated as Level 1 within the valuation hierarchy.

Redemption of Senior Subordinated Notes. In October 2013, the Company paid $254.0 million to redeem all of its $250.0 million aggregate principal amount of the 2014 Notes at a redemption price of 101.595%. Concurrent with this redemption, the Company paid all accrued and unpaid interest on the 2014 Notes up to but not including the redemption date. The Company financed the redemption of the 2014 Notes with proceeds from the issuance of the Senior Notes, as discussed above. As a result of the redemption, Whiting recognized a $4.4 million loss on early extinguishment of debt, which consisted of a cash charge of $4.0 million related to the redemption premium on the 2014 Notes and a non-cash charge of $0.4 million related to the acceleration of unamortized debt issuance costs.

The Senior Notes are unsecured obligations of Whiting Petroleum Corporation and are subordinated to all of the Company's secured indebtedness, which consists of Whiting Oil and Gas' credit agreement. The 6.5% Senior Subordinated Notes due 2018 (the "2018 Notes") are also unsecured obligations of Whiting Petroleum Corporation and are subordinated to all of the Company's senior debt, which currently consists of the Senior Notes and Whiting Oil and Gas' credit agreement. The Company's obligations under the 2018 Notes and the Senior Notes are fully and unconditionally guaranteed by the Company's 100%-owned subsidiary, Whiting Oil and Gas (the "Guarantor"). Any subsidiaries other than the Guarantor are minor subsidiaries as defined by Rule 3-10(h)(6) of Regulation S-X of the SEC. Whiting Petroleum Corporation has no assets or operations independent of this debt and its investments in its consolidated subsidiaries.

5. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations represent the present value of estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage, and land restoration (including removal of certain onshore and offshore facilities in California) in accordance with applicable local, state and federal laws. The Company follows FASB ASC Topic 410, Asset Retirement and Environmental Obligations, to determine its asset retirement obligation amounts by calculating the present value of the estimated future cash outflows associated with its plug and abandonment obligations. The current portions at December 31, 2013 and 2012 were $9.7 million and $11.6 million, respectively, and are included in accrued liabilities and other. Revisions to the liability typically occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells. The following table provides a reconciliation of the Company's asset retirement obligations for the year ended December 31, 2013 and 2012 (in thousands):

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	Year Ended December 31, 2013	2012
Asset retirement obligation at January 1	$ 97,818	$ 69,721
Additional liability incurred	17,535	9,292
Revisions in estimated cash flows	12,225	23,162
Accretion expense	10,608	7,263
Obligations on sold properties	(3,630)	(4)
Liabilities settled	(8,408)	(11,616)
Asset retirement obligation at December 31	$ 126,148	$ 97,818

6. DERIVATIVE FINANCIAL INSTRUMENTS

The Company is exposed to certain risks relating to its ongoing business operations, and Whiting uses derivative instruments to manage its commodity price risk. Whiting follows FASB ASC Topic 815, Derivatives and Hedging, to account for its derivative financial instruments.

Commodity Derivative Contracts—Historically, prices received for crude oil and natural gas production have been volatile because of seasonal weather patterns, supply and demand factors, worldwide political factors and general economic conditions. Whiting enters into derivative contracts, primarily costless collars and swaps, to achieve a more predictable cash flow by reducing its exposure to commodity price volatility. Commodity derivative contracts are thereby used to ensure adequate cash flow to fund the Company's capital programs and to manage returns on acquisitions and drilling programs. Costless collars are designed to establish floor and ceiling prices on anticipated future oil or gas production, while swaps are designed to establish a fixed price for anticipated future oil or gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The Company does not enter into derivative contracts for speculative or trading purposes.

Whiting Derivatives. The table below details the Company's costless collar derivatives, including its proportionate share of Trust II derivatives, entered into to hedge forecasted crude oil production revenues, as of February 6, 2014.

		Whiting Petroleum Corporation	
Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	Weighted Average NYMEX Price Collar Ranges for Crude Oil (per Bbl)
Collars	Jan – Dec 2014	49,290	$ 80.00 - $122.50
Three-way collars (1)	Jan – Dec 2014	15,280,000	$70.94 - $85.00 - $103.35
	Total	15,329,290	

(1) A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The sold call establishes a maximum price (ceiling) Whiting will receive for the volumes under contract. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put

(sub-floor), at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price.

In March 2013, Whiting entered into certain crude oil swap contracts in order to achieve more predictable cash flows and manage returns on certain oil and gas properties that the Company was considering for monetization. Accordingly, the acquisition of these swap contracts and cash receipts from settlements of these swap positions have been reflected as an investing activity in the statement of cash flows. On July 15, 2013, upon closing of the sale of the Postle Properties discussed in the Acquisitions and Divestitures footnote, these crude oil swaps were novated to the buyer. Cash settlements that do not relate to investing derivatives or that do not have a significant financing element are reflected as operating activities in the statement of cash flows.

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Derivatives Conveyed to Whiting USA Trust II. In connection with the Company's conveyance in March 2012 of a term net profits interest to Trust II and related sale of 18,400,000 Trust II units to the public, the right to any future hedge payments made or received by Whiting on certain of its derivative contracts have been conveyed to Trust II, and therefore such payments will be included in Trust II's calculation of net proceeds. Under the terms of the aforementioned conveyance, Whiting retains 10% of the net proceeds from the underlying properties, which results in third-party public holders of Trust II units receiving 90%, and Whiting retaining 10%, of the future economic results of commodity derivative contracts conveyed to Trust II. The relative ownership of the future economic results of such commodity derivatives is reflected in the tables below. No additional hedges are allowed to be placed on Trust II assets.

The 10% portion of Trust II derivatives that Whiting has retained the economic rights to (and which are also included in the first derivative table above) are as follows:

		Whiting Petroleum Corporation	
Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	NYMEX Price Collar Ranges for Crude Oil (per Bbl)
Collars	Jan – Dec 2014	49,290	$80.00 - $122.50

The 90% portion of Trust II derivative contracts of which Whiting has transferred the economic rights to third-party public holders of Trust II units (and which have not been reflected in the above tables) are as follows:

		Third-party Public Holders of Trust II Units	
Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	NYMEX Price Collar Ranges for Crude Oil (per Bbl)
Collars	Jan – Dec 2014	443,610	$80.00 - $122.50

Embedded Commodity Derivative Contract—In May 2011, Whiting entered into a long-term contract to purchase CO2 from 2015 through 2029 for use in its enhanced oil recovery project that is being carried out at its North Ward Estes field in Texas. This contract contains a price adjustment clause that is linked to changes in NYMEX crude oil prices. The Company has determined that the portion of this contract linked to NYMEX oil prices is not clearly and closely related to the host contract, and the Company has therefore bifurcated this embedded pricing feature from its host contract and reflected it at fair value in the consolidated financial statements. As of December 31, 2013, the estimated fair value of the embedded derivative in this CO2 purchase contract was an asset of $36.4 million.

Although CO2 is not a commodity that is actively traded on a public exchange, the market price for CO2 generally fluctuates in tandem with increases or decreases in crude oil prices. When Whiting enters into a long-term CO2 purchase contract where the price of CO2 is fixed and does not adjust with changes in oil prices, the Company is exposed to the risk of paying higher than the market rate for CO2 in a climate of declining oil and CO2 prices. This in turn could have a negative impact on the project economics of the Company's CO2 flood at North Ward Estes. As a result, the Company reduces its exposure to this risk by entering into certain CO2 purchase contracts which have prices that fluctuate along with changes in crude oil prices.

Derivative Instrument Reporting—All derivative instruments are recorded in the consolidated financial statements at fair value, other than derivative instruments that meet the "normal purchase normal sale" exclusion. The following tables summarize the effects of commodity derivative instruments on the consolidated statements of income for the year ended December 31, 2013 and 2012 (in thousands):

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ASC 815 Cash Flow Hedging Relationships (1)	Income Statement Classification	Gain (Loss) Reclassified from AOCI into Income (Effective Portion) (1) Year Ended December 31, 2013	2012
Commodity contracts	Gain (loss) on hedging activities	$ (1,958)	$ 2,338

(1) Effective April 1, 2009, the Company elected to de-designate all of its commodity derivative contracts that had been previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively. As a result, such mark-to-market values at March 31, 2009 were frozen in AOCI as of the de-designation date and were being reclassified into earnings as the original hedged transactions affected income. As of December 31, 2013, all amounts had been reclassified into earnings.

Not Designated as ASC 815 Hedges	Income Statement Classification	(Gain) Loss Recognized in Income Year Ended December 31, 2013	2012
Commodity contracts	Commodity derivative (gain) loss, net	$ 20,503	$ (75,782)
Embedded commodity contracts	Commodity derivative (gain) loss, net	(12,701)	(10,129)
Total		$ 7,802	$ (85,911)

Offsetting of Derivative Assets and Liabilities. With each individual derivative counterparty, the Company typically has numerous hedge positions that span a several-month time period and that typically result in both fair value asset and liability positions held with that counterparty, which positions are all offset to a single fair value asset or liability amount at the end of each reporting period. The Company nets its derivative instrument fair value amounts executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The following tables summarize the location and fair value amounts of all derivative instruments in the consolidated balance sheets, as well as the gross recognized derivative assets, liabilities and amounts offset in the consolidated balance sheets (in thousands):

		December 31, 2013 (1)		
Not Designated as ASC 815 Hedges	Balance Sheet Classification	Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets:				
Commodity contracts	Prepaid expenses and other	$ 23,752	$ (22,478)	$ 1,274
Embedded commodity contracts	Other long-term assets	36,416	-	36,416
Total derivative assets		$ 60,168	$ (22,478)	$ 37,690
Derivative liabilities:				
Commodity contracts	Current derivative liabilities	$ 25,960	$ (22,478)	$ 3,482
Total derivative liabilities		$ 25,960	$ (22,478)	$ 3,482

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Not Designated as ASC 815 Hedges	Balance Sheet Classification	December 31, 2012 (1) Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets:				
Commodity contracts	Prepaid expenses and other	$ 40,909	$ (31,437)	$ 9,472
Commodity contracts	Other long-term assets	4,053	(2,189)	1,864
Embedded commodity contracts	Other long-term assets	24,038	(323)	23,715
Total derivative assets		$ 69,000	$ (33,949)	$ 35,051
Derivative liabilities:				
Commodity contracts	Current derivative liabilities	$ 53,392	$ (31,437)	$ 21,955
Commodity contracts	Non-current derivative liabilities	3,867	(2,189)	1,678
Embedded commodity contracts	Non-current derivative liabilities	323	(323)	-
Total derivative liabilities		$ 57,582	$ (33,949)	$ 23,633

(1) Because counterparties to the Company's derivative contracts are lenders under Whiting Oil and Gas' credit agreement, which eliminates its need to post or receive collateral associated with its derivative positions, columns for cash collateral pledged or received have not been presented in the tables above.

Contingent Features in Derivative Instruments. None of the Company's derivative instruments contain credit-risk-related contingent features. Counterparties to the Company's derivative contracts are high credit-quality financial institutions that are lenders under Whiting's credit agreement. The Company uses only credit agreement participants to hedge with, since these institutions are secured equally with the holders of Whiting's bank debt, which eliminates the potential need to post collateral when Whiting is in a derivative liability position. As a result, the Company is not required to post letters of credit or corporate guarantees for its derivative counterparties in order to secure contract performance obligations.

7. FAIR VALUE MEASUREMENTS

The Company follows FASB ASC Topic 820, Fair Value Measurement and Disclosure, which establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1: Quoted Prices in Active Markets for Identical Assets – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2: Significant Other Observable Inputs – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
-

Level 3: Significant Unobservable Inputs – inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon 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 in its entirety requires judgment and considers factors specific to the asset or liability. The Company reflects transfers between the three levels at the beginning of the reporting period in which the availability of observable inputs no longer justifies classification in the original level.

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The following tables present information about the Company's financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2013 and 2012, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

	Level 1	Level 2	Level 3	Total Fair Value December 31, 2013
Financial Assets				
Commodity derivatives – current	$ -	$ 1,274	$ -	$ 1,274
Embedded commodity derivatives – non-current	-	-	36,416	36,416
Total financial assets	$ -	$ 1,274	$ 36,416	$ 37,690
Financial Liabilities				
Commodity derivatives – current	$ -	$ 3,482	$ -	$ 3,482
Total financial liabilities	$ -	$ 3,482	$ -	$ 3,482

	Level 1	Level 2	Level 3	Total Fair Value December 31, 2012
Financial Assets				
Commodity derivatives – current	$ -	$ 9,472	$ -	$ 9,472
Commodity derivatives – non-current	-	1,864	-	1,864
Embedded commodity derivatives – non-current	-	-	23,715	23,715
Total financial assets	$ -	$ 11,336	$ 23,715	$ 35,051
Financial Liabilities				
Commodity derivatives – current	$ -	$ 21,955	$ -	$ 21,955
Commodity derivatives – non-current	-	1,678	-	1,678
Total financial liabilities	$ -	$ 23,633	$ -	$ 23,633

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

Commodity Derivatives. Commodity derivative instruments consist of costless collars and swap contracts for crude oil. The Company's costless collars and swaps are valued based on an income approach. Both the option and swap models consider various assumptions, such as quoted forward prices for commodities, time value and volatility factors. These assumptions are observable in the marketplace throughout the full term of the contract, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace, and are therefore designated as Level 2 within the valuation hierarchy. The discount rates used in the fair values of these instruments include a measure of either the Company's or the counterparty's nonperformance risk, as appropriate. The Company utilizes its counterparties' valuations to assess the reasonableness of its own valuations.

Embedded Commodity Derivatives. The embedded commodity derivative relates to a long-term CO_2 purchase contract, which has a price adjustment clause that is linked to changes in NYMEX crude oil prices. Whiting has determined that the portion of this contract linked to NYMEX oil prices is not clearly and closely related to its corresponding host contract, and the Company has therefore bifurcated this embedded pricing feature from the host contract and reflected it at fair value in its consolidated financial statements. This embedded commodity derivative is valued based on an income approach. The option model used in the valuation considers various assumptions, including quoted forward prices for commodities, LIBOR discount rates and either the Company's or the counterparty's nonperformance risk, as appropriate.

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The assumptions used in the CO2 contract valuation include inputs that are both observable in the marketplace as well as unobservable during the term of the contract. With respect to forward prices for NYMEX crude oil where there is a lack of price transparency in certain future periods, such unobservable oil price inputs are significant to the CO2 contract valuation methodology, and the contract's fair value is therefore designated as Level 3 within the valuation hierarchy.

Level 3 Fair Value Measurements. A third-party valuation specialist is utilized on a quarterly basis to determine the fair value of the embedded commodity derivative instrument designated as Level 3. The Company reviews this valuation (including the related model inputs and assumptions) and analyzes changes in fair value measurements between periods. The Company corroborates such inputs, calculations and fair value changes using various methodologies, and reviews unobservable inputs for reasonableness utilizing relevant information from other published sources.

The following table presents a reconciliation of changes in the fair value of financial assets (liabilities) designated as Level 3 in the valuation hierarchy for the year ended December 31, 2013 and 2012 (in thousands):

	Year Ended December 31, 2013	2012
Fair value asset, beginning of period	$ 23,715	$ 12,980
Unrealized gains (losses) on embedded commodity derivative contracts included in earnings (1)	12,701	10,735
Transfers into (out of) Level 3	-	-
Fair value asset, end of period	$ 36,416	$ 23,715

(1) Included in commodity derivative (gain) loss, net in the consolidated statements of income.

Quantitative Information About Level 3 Fair Value Measurements. The significant unobservable inputs used in the fair value measurement of the Company's embedded commodity derivative contract designated as Level 3 are as follows:

	Fair Value at December 31, 2013 (in thousands)	Valuation Technique	Unobservable Input	Range (per Bbl)
Embedded commodity derivative	$ 36,416	Option model	Future prices of NYMEX crude oil after March 31, 2022	$79.87 - $95.75

Sensitivity to Changes In Significant Unobservable Inputs. As presented in the table above, the significant unobservable inputs used in the fair value measurement of Whiting's embedded commodity derivative within its CO2 purchase contract are the future prices of NYMEX crude oil from April 2022 to December 2029. Significant increases (decreases) in these unobservable inputs in isolation would result in a significantly lower (higher) fair value asset measurement.

Nonrecurring Fair Value Measurements. The Company applies the provisions of the fair value measurement standard to its nonrecurring, non-financial measurements, including proved oil and gas property impairments. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances. The following tables present information about the Company's non-financial assets and liabilities measured at fair value on a nonrecurring basis as of December 31, 2013 and 2012, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

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	Net Carrying Value as of December 31, 2013	Fair Value Measurements Using Level 1	Level 2	Level 3	Loss (Before Tax) Year Ended December 31, 2013
Proved property impairments (1)	$ 106,114	$ -	$ -	$ 106,114	$ 267,109

(1) During the year ended December 31, 2013, proved oil and gas properties with a carrying amount of $373.2 million were written down to their fair value of $106.1 million, resulting in a non-cash impairment charge of $267.1 million. The impairment consisted of (i) a $220.8 million write-down in the Rocky Mountains region and Michigan related to the decrease in the forward price curve for natural gas at December 31, 2013 and the associated decline in gas reserves in those areas and (ii) a $46.3 million write-down in the Rocky Mountains region related to well performance and associated changes in reserves during the fourth quarter of 2013.

	Net Carrying Value as of December 31, 2012	Fair Value Measurements Using Level 1	Level 2	Level 3	Loss (Before Tax) Year Ended December 31, 2012
Proved property impairments (1)	$ 23,473	$ -	$ -	$ 23,473	$ 46,924

(1) During the year ended December 31, 2012, proved oil and gas properties with a carrying amount of $70.4 million were written down to their fair value of $23.5 million, resulting in a non-cash impairment charge of $46.9 million. The impairment consisted primarily of a $46.3 million write-down in the Rocky Mountains region related to changes in estimated reserves at December 31, 2012.

The following methods and assumptions were used to estimate the fair values of the non-financial liabilities in the tables above:

Proved Property Impairments. Once the Company has determined that a proved property impairment has occurred, the cost of the property is written down to its fair value, which is determined using net discounted future cash flows from the producing property, and such discounted cash flows are developed using the income approach. The discounted cash flows are based on management's expectations for the future. Unobservable inputs include estimates of future oil and gas production from the Company's reserve reports, commodity prices based on sales contract terms or NYMEX forward price curves as of the date of the estimate (adjusted for basis differentials), estimated operating and development costs, and a risk-adjusted discount rate of 15% (all of which are designated as Level 3 inputs within the fair value hierarchy).

8. DEFERRED COMPENSATION

Production Participation Plan—The Company has a Production Participation Plan (the "Plan") in which all employees participate. On an annual basis, interests in oil and gas properties acquired, developed or sold during the year are allocated to the Plan as determined annually by the Compensation Committee of the Company's Board of Directors. Once allocated, the interests (not legally conveyed) are fixed. Interest allocations prior to 1995 consisted of 2%-3% overriding royalty interests. Interest allocations since 1995 have been 1.75%-5% of oil and gas sales less lease operating expenses and production taxes.

Payments of 100% of the year's Plan interests to employees and the vested percentages of former employees in the year's Plan interests are made annually in cash after year-end. Accrued compensation expense under the Plan for the years ended December 31, 2013, 2012 and 2011 amounted to $66.5 million, $44.7 million and $34.1 million, respectively, charged to general and administrative expense and $6.8 million, $4.6 million and $4.2 million, respectively, charged to exploration expense.

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Employees vest in the Plan ratably at 20% per year over a five-year period. Pursuant to the terms of the Plan, (i) employees who terminate their employment with the Company are entitled to receive their vested allocation of future Plan year payments on an annual basis; (ii) employees will become fully vested at age 62, regardless of when their interests would otherwise vest; and (iii) any forfeitures inure to the benefit of the Company.

The Company uses average historical prices to estimate the vested long-term Production Participation Plan liability. At December 31, 2013, the Company used three-year average historical NYMEX prices of $95.60 for crude oil and $3.49 for natural gas to estimate this liability. The Company records the expense associated with changes in the present value of estimated future payments under the Plan as a separate line item in the consolidated statements of income. If the Company were to terminate the Plan or upon a change in control of the Company (as defined in the Plan), all employees fully vest and the Company would distribute to each Plan participant an amount, based upon the valuation method set forth in the Plan, in a lump sum payment twelve months after the date of termination or within one month after a change in control event. Based on current strip prices at December 31, 2013, if the Company elected to terminate the Plan or if a change of control event occurred, it is estimated that the fully vested lump sum cash payment to employees would approximate $186.7 million. This amount includes $19.2 million attributable to proved undeveloped oil and gas properties and $73.3 million relating to the short-term portion of the Plan liability, which has been reflected as a current payable in accrued liabilities and other, and was paid in January and February 2014. The ultimate sharing contribution for proved undeveloped oil and gas properties will be awarded in the year of Plan termination or change of control. However, the Company has no intention to terminate the Plan.

The following table presents changes in the Plan's estimated long-term liability (in thousands):

	Year Ended December 31, 2013	2012
Long-term Production Participation Plan liability at January 1	$ 94,483	$ 80,659
Change in liability for accretion, vesting, changes in estimates and new Plan year activity	66,284	63,135
Accrued compensation expense reflected as a current liability	(73,264)	(49,311)
Long-term Production Participation Plan liability at December 31	$ 87,503	$ 94,483

Of the aggregate $73.3 million of accrued compensation under the Plan as of December 31, 2013, $23.9 million relates to the sale of the Postle Properties, which is further described in the Acquisitions and Divestitures footnote. This property sale also resulted in an offsetting benefit of $19.4 million realized related to the reduction in the Company's long-term Plan liability.

401(k) Plan—The Company has a defined contribution retirement plan for all employees. The plan is funded by employee contributions and discretionary Company contributions. The Company's contributions for 2013, 2012 and 2011 were $7.9 million, $5.9 million and $5.0 million, respectively. Employees vest in employer contributions at 20% per year of completed service.

9. SHAREHOLDERS' EQUITY AND NONCONTROLLING INTEREST

Common Stock—In May 2011, Whiting's stockholders approved an amendment to the Company's Restated Certificate of Incorporation to increase the number of authorized shares of common stock from 175,000,000 shares to 300,000,000 shares.

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Stock Split. On January 26, 2011, the Company's Board of Directors approved a two-for-one split of the Company's shares of common stock to be effected in the form of a stock dividend. As a result of the stock split, stockholders of record on February 7, 2011 received one additional share of common stock for each share of common stock held. The additional shares of common stock were distributed on February 22, 2011. Concurrently with the payment of such stock dividend in February 2011, there was a transfer from additional paid-in capital to common stock of $0.1 million, which amount represents $0.001 per share (being the par value thereof) for each share of common stock so issued. The common stock dividend resulted in the conversion price for Whiting's 6.25% Convertible Perpetual Preferred Stock being adjusted from $43.4163 to $21.70815.

6.25% Convertible Perpetual Preferred Stock—In June 2009, the Company completed a public offering of 6.25% convertible perpetual preferred stock ("preferred stock"), selling 3,450,000 shares at a price of $100.00 per share. As a result of voluntary conversions and the Company exercising its right to mandatorily convert shares of preferred stock effective June 27, 2013, all 172,129 shares of preferred stock outstanding on March 31, 2013, were converted into 792,919 shares of common stock. As of December 31, 2013, no shares of preferred stock remained issued or outstanding.

Each holder of the preferred stock was entitled to an annual dividend of $6.25 per share to be paid quarterly in cash, common stock or a combination thereof on March 15, June 15, September 15 and December 15, when and if such dividend had been declared by Whiting's board of directors.

Equity Incentive Plan—At the Company's 2013 Annual Meeting held on May 7, 2013, shareholders approved the Whiting Petroleum Corporation 2013 Equity Incentive Plan (the "2013 Equity Plan"), which replaced the Whiting Petroleum Corporation 2003 Equity Incentive Plan (the "2003 Equity Plan") and includes the authority to issue 5,300,000 shares of the Company's common stock. Upon shareholder approval of the 2013 Equity Plan, the 2003 Equity Plan was terminated. The 2003 Equity Plan continues to govern awards that were outstanding as of the date of its termination, which remain in effect pursuant to their terms. Any shares netted or forfeited after May 7, 2013 under the 2003 Equity Plan will be available for future issuance under the 2013 Equity Plan. Under the 2013 Equity Plan, no employee or officer participant may be granted options for more than 600,000 shares of common stock, stock appreciation rights relating to more than 600,000 shares of common stock, or more than 300,000 shares of restricted stock during any calendar year. As of December 31, 2013, 5,380,594 shares of common stock remained available for grant under the 2013 Equity Plan.

For the years ended December 31, 2013, 2012 and 2011, total stock compensation expense recognized for restricted share awards and stock options was $22.4 million, $18.2 million and $13.5 million, respectively.

Restricted Shares. Restricted stock awards for executive officers and employees generally vest ratably over a three-year service period, while awards to directors generally vest ratably over a one or three-year service period. The Company uses historical data and projections to estimate expected employee behaviors related to restricted stock forfeitures. The expected forfeitures are then included as part of the grant date estimate of compensation cost. For service-based restricted stock awards, the grant date fair value is determined based on the closing bid price of the Company's common stock on the grant date.

In January 2013, 2012 and 2011, 751,872 shares, 444,501 shares and 201,420 shares, respectively, of restricted stock, subject to certain market-based vesting criteria in addition to the standard three-year service condition, were granted to executive officers under the Equity Plan. Vesting each year is subject to the condition that Whiting's stock price increases by a greater percentage (or decreases by a lesser percentage) than the average percentage increase (or decrease, respectively) of the stock prices of a peer group of companies. The market-based conditions must be met in order for the stock awards to vest, and it is therefore possible that no shares could vest in one or more of the three-year vesting periods. However, the Company recognizes compensation expense for awards subject to market conditions regardless of whether it becomes probable that these conditions will be achieved or not, and compensation expense is not reversed if vesting does not actually occur.

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For these awards subject to market conditions, the grant date fair value was estimated using a Monte Carlo valuation model. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility was calculated based on the historical volatility of Whiting's common stock, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with the three-year vesting period. The key assumptions used in valuing the market-based restricted shares were as follows:

	2013	2012	2011
Number of simulations	65,000	65,000	65,000
Expected volatility	43.1%	51.9%	75.8%
Risk-free rate	0.41%	0.35%	1.00%
Dividend yield	-	-	-

The grant date fair value of the market-based restricted stock as determined by the Monte Carlo valuation model was $23.01 per share, $29.45 per share and $42.20 per share in January 2013, 2012 and 2011, respectively.

The following table shows a summary of the Company's nonvested restricted stock as of December 31, 2011, 2012 and 2013 as well as activity during the years then ended:

	Number of Shares	Weighted Average Grant Date Fair Value
Restricted stock awards nonvested, January 1, 2011	869,370	$ 16.27
Granted	304,355	48.48
Vested	(429,136)	15.32
Forfeited	(20,194)	33.53
Restricted stock awards nonvested, December 31, 2011	724,395	29.88
Granted	592,400	34.45
Vested	(357,170)	17.91
Forfeited	(8,599)	51.72
Restricted stock awards nonvested, December 31, 2012	951,026	37.02
Granted	940,792	27.59
Vested	(347,824)	35.32
Forfeited	(99,684)	30.95
Restricted stock awards nonvested, December 31, 2013	1,444,310	$ 31.71

As of December 31, 2013, there was $11.8 million of total unrecognized compensation cost related to unvested restricted stock granted under the stock incentive plans. That cost is expected to be recognized over a weighted average period of 1.7 years. For the years ended December 31, 2013, 2012 and 2011, the total fair value of restricted stock vested was $16.8 million, $18.9 million and $26.0 million, respectively.

Stock Options. In January 2012 and 2011, 45,359 stock options and 80,820 stock options, respectively, were granted under the 2003 Equity Plan to certain executive officers of the Company with exercise prices equal to the closing market price of the Company's common stock on the grant date. There were no stock options granted under either the 2003 Equity Plan or the 2013 Equity Plan during 2013. These stock options vest ratably over a three-year service period from the grant date and are exercisable immediately upon vesting through the tenth anniversary of the grant date.

The Company uses a Black-Scholes option-pricing model to estimate the fair value of stock option awards. Because the Company first granted stock options in 2009, it does not have historical exercise data upon which to estimate the expected term of the options. As such, the Company has elected to estimate the expected term of the stock options granted using the "simplified" method for "plain vanilla" options. The expected volatility at the grant date is based on the historical volatility of Whiting's common stock, and the risk-free interest rate is determined based on the yield on U.S. Treasury strips with maturities similar to those of the expected term of the stock options. The following table summarizes the assumptions used to estimate the grant date fair value of stock options awarded in each respective year:

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	2012	2011
Risk-free interest rate	1.19%	2.47%
Expected volatility	61.4%	59.3%
Expected term	6.0 yrs.	6.0 yrs.
Dividend yield	-	-

The grant date fair value of the stock options awarded, as determined by the Black-Scholes valuation model, was $28.88 per share and $34.15 per share in January 2012 and 2011, respectively.

The following table shows a summary of the Company's stock options outstanding as of December 31, 2011, 2012 and 2013 as well as activity during the years then ended:

	Number of Options	Weighted Average Exercise Price per Share	Aggregate Intrinsic Value (in thousands)	Weighted Average Remaining Contractual Term (in years)
Options outstanding at January 1, 2011	296,516	$ 16.78		
Granted	80,820	60.28		
Exercised	-	-	$ -	
Forfeited or expired	-	-		
Options outstanding at December 31, 2011	377,336	26.09		
Granted	45,359	51.22		
Exercised	-	-	$ -	
Forfeited or expired	-	-		
Options outstanding at December 31, 2012	422,695	28.79		
Granted	-	-		
Exercised	-	-	$ -	
Forfeited or expired	(1,855)	60.28		
Options outstanding at December 31, 2013	420,840	$ 28.65	$ 13,979.6	5.9
Options vested and expected to vest at December 31, 2013	420,840	$ 28.65	$ 13,979.6	5.9
Options exercisable at December 31, 2013	365,511	$ 24.61	$ 13,617.8	5.7

Unrecognized compensation cost as of December 31, 2013 related to unvested stock option awards was $0.2 million, which is expected to be recognized over a period of one year.

Rights Agreement—In 2006, the Board of Directors of the Company declared a dividend of one preferred share purchase right (a "Right") for each outstanding share of common stock of the Company payable to the stockholders of record as of March 2, 2006. As a result of the two-for-one split of the Company's common stock effective February 22, 2011, one-half of a Right is now associated with each share of common stock. Each Right entitles the registered holder to purchase from the Company one one-hundredth of a share of Series A Junior Participating Preferred Stock, par value $0.001 per share ("Preferred Shares"), of the Company at a price of $180.00 per one one-hundredth of a Preferred Share, subject to adjustment. If any person becomes a 15% or more stockholder of the Company, then each Right (subject to certain limitations) will entitle its holder to purchase, at the Right's then current exercise price, a number of shares of common stock of the Company or of the acquirer having a market value at the time of twice the Right's per share exercise price. The Company's Board of Directors may redeem the Rights for $0.001 per Right at any time prior to the time when the Rights become exercisable. Unless the Rights are redeemed, exchanged or terminated earlier, they will expire on February 23, 2016.

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Noncontrolling Interest—The noncontrolling interest represents an unrelated third party's 25% ownership interest in Sustainable Water Resources, LLC. The table below summarizes the activity for the equity attributable to the noncontrolling interest (in thousands):

	Year Ended December 31,	
	2013	2012
Balance at January 1	$ 8,184	$ 8,274
Net income (loss)	(52)	(90)
Balance at December 31	$ 8,132	$ 8,184

10. INCOME TAXES

Income tax expense consists of the following (in thousands):

	Year Ended December 31,		
	2013	2012	2011
Current income tax expense (refund):			
Federal	$ 7,060	$ -	$ 107
State	(6,074)	(669)	3,746
Total current income tax expense	986	(669)	3,853
Deferred income tax expense:			
Federal	196,787	233,468	272,653
State	8,095	15,113	12,185
Total deferred income tax expense	204,882	248,581	284,838
Total	$ 205,868	$ 247,912	$ 288,691

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

	Year Ended December 31,		
	2013	2012	2011
U.S. statutory income tax expense	$ 200,155	$ 231,704	$ 273,112
State income taxes, net of federal benefit	13,962	14,444	16,602
State income tax credits	(10,525)	-	-
Statutory depletion	(796)	(620)	(697)
Enacted changes in state tax laws	(1,416)	-	(1,842)
Permanent items	2,122	1,524	1,420
Other	2,366	860	96
Total	$ 205,868	$ 247,912	$ 288,691

The principal components of the Company's deferred income tax assets and liabilities at December 31, 2013 and 2012 were as follows (in thousands):

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	Year Ended December 31, 2013	2012
Deferred income tax assets:		
Net operating loss carryforward	$ 438,922	$ 520,980
Derivative instruments	-	19,957
Production Participation Plan liability	32,245	34,865
Tax sharing liability	9,439	8,312
Asset retirement obligations	23,642	19,759
Underwriter fees	10,974	12,677
Restricted stock compensation	13,384	9,852
Enhanced oil recovery credit carryforwards	7,946	7,946
Alternative minimum tax credit carryforwards	18,452	11,391
Foreign tax credit carryforwards	1,230	1,230
Other	2,004	1,508
Total deferred income tax assets	558,238	648,477
Less valuation allowances	(1,230)	(1,230)
Net deferred income tax assets	557,008	647,247
Deferred income tax liabilities:		
Oil and gas properties	1,675,916	1,555,142
Trust distributions	149,332	165,180
Derivative instruments	10,438	-
Total deferred income tax liabilities	1,835,686	1,720,322
Total net deferred income tax liabilities	$ 1,278,678	$ 1,073,075

As of December 31, 2013, we had federal net operating loss (“NOL”) carryforwards of $1,255.2 million. Of this amount, $50.5 million in NOL carryforwards relate to tax deductions for stock compensation that exceed stock compensation costs recognized for financial statement purposes. The benefit of these excess tax deductions will not be recognized as an NOL in the Company’s financial statements, until the related deductions reduce taxes payable and are thereby realized. The Company also has various state NOL carryforwards. The determination of the state NOL carryforwards is dependent upon apportionment percentages and state laws that can change from year to year and impact the amount of such carryforwards. If unutilized, the federal NOL will expire between 2027 and 2033, and the state NOLs will expire between 2014 and 2033.

EOR credits are a credit against federal income taxes for certain costs related to extracting high-cost oil, utilizing certain prescribed "enhanced" tertiary recovery methods. As of December 31, 2013, the Company had recognized aggregate EOR credits of $7.9 million that are available to offset regular federal income taxes in the future. These credits can be carried forward and will expire between 2023 and 2025. Federal EOR credits are subject to phase-out according to the level of average domestic crude oil prices. The EOR credit has been phased-out since 2006, but this phase-out affects only the periods for which EOR credits can be captured and not the periods in which such credits can be utilized.

The Company is subject to the alternative minimum tax ("AMT") principally due to its significant intangible drilling cost deductions. As of December 31, 2013, the Company had AMT credits totaling $18.5 million that are available to offset future regular federal income taxes. These credits do not expire and can be carried forward indefinitely.

At December 31, 2013, the Company's foreign tax credit carryforwards totaled $1.2 million, which will expire between 2014 and 2016. As of December 31, 2013, a valuation allowance of $1.2 million was established in full for the foreign tax credit carryforwards because the Company determined that it was more likely than not that the benefit from these deferred tax assets will not be realized due to the divestiture of all foreign operations.

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Net deferred income tax liabilities were classified in the consolidated balance sheets as follows (in thousands):

	Year Ended December 31, 2013	2012
Assets:		
Current deferred income taxes	$ -	$ -
Liabilities:		
Current deferred income taxes	648	9,394
Non-current deferred income taxes	1,278,030	1,063,681
Net deferred income tax liabilities	$ 1,278,678	$ 1,073,075

The following table summarizes the activity related to the Company's liability for unrecognized tax benefits (in thousands):

	Year Ended December 31, 2013	2012	2011
Beginning balance at January 1	$ 170	$ 299	$ 299
Decrease related to tax position taken in a prior period	-	(129)	-
Ending balance at December 31	$ 170	$ 170	$ 299

Included in the unrecognized tax benefit balance at December 31, 2013, are $0.2 million of tax positions, the allowance of which would positively affect the annual effective income tax rate. For the year ended December 31, 2013, the Company did not recognize any interest or penalties with respect to unrecognized tax benefits, nor did the Company have any such interest or penalties previously accrued. The Company believes that it is reasonably possible that no increases or decreases to unrecognized tax benefits will occur in the next twelve months.

The Company files income tax returns in the U.S. federal jurisdiction and in various states, each with varying statutes of limitations. The 2010 through 2013 tax years generally remain subject to examination by federal and state tax authorities.

11. EARNINGS PER SHARE

The reconciliations between basic and diluted earnings per share are as follows (in thousands, except per share data):

	Year Ended December 31, 2013	2012	2011
Basic Earnings Per Share			
Numerator:			
Net income available to shareholders	$ 366,055	$ 414,189	$ 491,687
Preferred stock dividends (1)	(494)	(1,077)	(1,077)
Net income available to common shareholders, basic	$ 365,561	$ 413,112	$ 490,610
Denominator:			
Weighted average shares outstanding, basic	118,260	117,601	117,345
Diluted Earnings Per Share			
Numerator:			

Net income available to common shareholders, basic	$ 365,561	$ 413,112	$ 490,610
Preferred stock dividends	538	1,077	1,077
Adjusted net income available to common shareholders, diluted	$ 366,099	$ 414,189	$ 491,687
Denominator:			
Weighted average shares outstanding, basic	118,260	117,601	117,345
Restricted stock and stock options	957	633	529
Convertible perpetual preferred stock	371	794	794
Weighted average shares outstanding, diluted	119,588	119,028	118,668
Earnings per common share, basic	$ 3.09	$ 3.51	$ 4.18
Earnings per common share, diluted	$ 3.06	$ 3.48	$ 4.14

(1) For the year ended December 31, 2013, amount includes a decrease of $0.04 million in preferred stock dividends for preferred stock dividends accumulated. There were no accumulated dividend adjustments for the years ended December 31, 2012 and 2011.

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For the year ended December 31, 2013, the diluted earnings per share calculation excludes the dilutive effect of (i) 173,778 incremental shares of restricted stock that did not meet its market-based vesting criteria as of December 31, 2013, and (ii) 8,689 common shares for stock options that were out-of-the-money. For the year ended December 31, 2012, the diluted earnings per share calculation excludes (i) the dilutive effect of 141,807 incremental shares of restricted stock that did not meet its market-based vesting criteria as of December 31, 2012, and (ii) the anti-dilutive effect of 7,720 common shares for stock options that were out-of-the-money. For the year ended December 31, 2011, the diluted earnings per share calculation excludes the dilutive effect of (i) 113,228 incremental shares of restricted stock that did not meet its market-based vesting criteria as of December 31, 2011, and (ii) 2,285 common shares for stock options that were out-of-the-money.

12. RELATED PARTY TRANSACTIONS

Whiting USA Trust I—As a result of Whiting's retained ownership of 15.8%, or 2,186,389 units in Whiting USA Trust I, it is a related party of the Company. The following table summarizes the related party receivable and payable balances between the Company and Trust I as of December 31, 2013 and 2012 (in thousands):

	December 31, 2013	December 31, 2012
Assets		
Unit distributions due from Trust I (1)	$ 1,093	$ 929
Liabilities		
Unit distributions payable to Trust I (2)	$ 6,932	$ 5,731

(1) This amount represents Whiting's 15.8% interest in the net proceeds due from Trust I and is included within accounts receivable trade, net in the Company's consolidated balance sheets.

(2) This amount represents net proceeds from Trust I's underlying properties that the Company has received between the last Trust I distribution date and December 31, 2013 and 2012, respectively, but which the Company has not yet distributed to Trust I as of December 31, 2013 and 2012, respectively. Due to ongoing processing of Trust I revenues and expenses after December 31, 2013 and 2012, the amount of Whiting's next scheduled distribution to Trust I, and the related distribution by Trust I to its unitholders, will differ from this amount. These amounts are included within accounts payable trade in the Company's consolidated balance sheet.

For the year ended December 31, 2013, Whiting paid $30.7 million, net of state tax withholdings, in unit distributions to Trust I and received $4.7 million in distributions back from Trust I pursuant to its retained ownership in 2,186,389 Trust I units.

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Tax Sharing Liability—Prior to Whiting's initial public offering in November 2003, it was a wholly-owned indirect subsidiary of Alliant Energy Corporation ("Alliant Energy"), and when the transactions discussed below were entered into, Alliant Energy was a related party of the Company. As of December 31, 2004 and thereafter, Alliant Energy was no longer a related party.

In 2003, the Company entered into a Tax Separation and Indemnification Agreement with Alliant Energy, whereby the Company and Alliant Energy made certain tax elections with the effect that the tax bases of Whiting's assets were increased. Such additional tax bases have resulted in increased income tax deductions for Whiting and, accordingly, have reduced income taxes otherwise payable by Whiting. Under this Tax Separation and Indemnification Agreement, the Company agreed to pay to Alliant Energy (each year from 2004 to 2013) 90% of the tax benefits the Company realized annually as a result of this step-up in tax bases. In 2014, Whiting is obligated to pay Alliant the present value of 90% of the remaining tax benefits expected to result from its increased tax bases, which payout assumes all such tax benefits will be realized in future years.

The final remaining payment of $23.9 million due Alliant Energy under this agreement has been reflected in the Company's consolidated balance sheets as a current liability at December 31, 2013. During 2013, 2012 and 2011, the Company made payments of $1.8 million, $2.3 million and $1.9 million, respectively, under this agreement and recognized interest expense of $3.1 million, $2.2 million and $2.1 million, respectively.

Alliant Energy Guarantee—The Company holds a 6% working interest in three offshore platforms in California and the related onshore plant and equipment. Alliant Energy has guaranteed the Company's obligation in the abandonment of these assets.

13. COMMITMENTS AND CONTINGENCIES

The table below shows the Company's minimum future payments under non-cancelable operating leases and unconditional purchase obligations as of December 31, 2013 (in thousands):

	Payments due by period						
	2014	2015	2016	2017	2018	Thereafter	Total
Non-cancelable leases	$ 6,279	$ 5,872	$ 5,387	$ 5,250	$ 4,629	$ 1,374	$ 28,791
Drilling rig contracts	87,610	48,531	1,755	-	-	-	137,896
Construction and drilling contract	31,066	-	2,900	6,900	4,100	-	44,966
Total	$ 124,955	$ 54,403	$ 10,042	$ 12,150	$ 8,729	$ 1,374	$ 211,653

Non-cancelable Leases—The Company leases 172,400 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2018, 47,900 square feet of office space in Midland, Texas expiring in 2020 and 20,000 square feet of office space in Dickinson, North Dakota expiring in 2016. In addition, the Company entered into a lease for several residential apartments in Watford City and Dickinson, North Dakota under an operating lease arrangement expiring in 2015. Rental expense for 2013, 2012 and 2011 amounted to $5.0 million, $5.7 million and $4.4 million, respectively. Minimum lease payments under the terms of non-cancelable operating leases as of December 31, 2013 are shown in the table above.

Drilling Rig Contracts—The Company currently has 12 drilling rigs under long-term contract, of which six drilling rigs expire in 2014, four in 2015 and two in 2016. All of these rigs are operating in the Rocky Mountains region. As of

December 31, 2013, early termination of the remaining contracts would require termination penalties of $101.1 million, which would be in lieu of paying the remaining drilling commitments of $137.9 million. No other drilling rigs working for the Company are currently under long-term contracts or contracts that cannot be terminated at the end of the well that is currently being drilled. During 2013, 2012 and 2011, the Company made payments of $92.8 million, $101.1 million and $49.8 million, respectively, under these long-term contracts, which are initially capitalized as a component of oil and gas properties and either depleted in future periods or written off as exploration expense. Two of these drilling rigs have price adjustment clauses that make their corresponding day rates fluctuate, and this component of those purchase obligations is therefore variable. Minimum drilling commitments under the terms of these contracts as of December 31, 2013 are shown in the table above.

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Construction and Drilling Contract—The Company entered into a contract whereby it is obligated to spend up to $51.4 million on the construction of certain facilities and field infrastructure and the drilling of forty-six CO2 wells in its Bravo Dome field. As of December 31, 2013, the Company had spent $6.4 million towards meeting this contractual commitment and had a remaining capital expenditure obligation of $45.0 million. If the Company fails to spend the required amounts by the dates set forth in the agreement, it will be required to pay the remaining unspent capital expenditures as liquidated damages. However, the Company expects to fulfill its obligations under this contract and therefore avoid any payments for deficiencies. The Company's remaining financial commitments under this agreement as of December 31, 2013 are shown in the table above. The Company does not have any volumetric CO2 delivery or supply commitments associated with this contract.

Purchase Contracts—The Company has three take-or-pay purchase agreements, one agreement expiring in December 2014, one agreement expiring in December 2017 and one agreement expiring in December 2029, whereby the Company has committed to buy certain volumes of CO2 for use in its EOR project in the North Ward Estes field in Texas. The purchase agreements are with two different suppliers. Under the terms of the agreements, the Company is obligated to purchase a minimum daily volume of CO2 (as calculated on an annual basis) or else pay for any deficiencies at the price in effect when the minimum delivery was to have occurred. In addition, the Company has one ship-or-pay agreement, expiring in December 2017, whereby it has committed to transport a minimum daily volume of CO2 via a certain pipeline or else pay for any deficiencies at a price stipulated in the contract.

The CO2 volumes planned for use in the Company's EOR project in the North Ward Estes field currently exceed the minimum daily volumes specified in all of these agreements. Therefore, the Company expects to avoid any payments for deficiencies. During 2013, 2012 and 2011, purchases and transportation of CO2 amounted to $88.1 million, $86.0 million and $69.8 million, respectively. Although minimum daily quantities are specified in the agreements, the actual CO2 volumes purchased or transported and their corresponding unit prices are variable over the term of the contracts. As a result, the future minimum payments for each of the five succeeding fiscal years are not fixed and determinable and are not therefore included in the table above. As of December 31, 2013, the Company estimated future commitments under these purchase agreements to approximate $632.6 million through 2029.

Delivery Commitments—The Company has various physical delivery contracts which require the Company to deliver fixed volumes of natural gas and crude oil. As of December 31, 2013, the Company had delivery commitments of 4.0 Bcf of natural gas for the year ended December 31, 2014, which relate to gas production at its Boies Ranch field in Rio Blanco County, Colorado and its Flat Rock field in Uintah County, Utah. As of December 31, 2013, the Company also had delivery commitments of 9.1 MMBbl, 11.0 MMBbl, 12.8 MMBbl, 14.6 MMBbl and 16.4 MMBbl of crude oil for the years ended December 31, 2015, 2016, 2017, 2018 and 2019, respectively. These delivery commitments relate to crude oil production at Whiting's Redtail field in the DJ Basin in Weld County, Colorado. The Company anticipates that future production from this field will be sufficient to meet the delivery commitments under these physical delivery contracts, and the Company therefore expects to avoid any payments for deficiencies. As a result, there is no financial obligation under these contracts.

Litigation—The Company is subject to litigation, claims and governmental and regulatory proceedings arising in the ordinary course of business. We accrue a loss contingency for these lawsuits and claims when it is probable that a loss has been incurred and the amount of the loss can be reasonably estimated. Accordingly, no material amounts for loss contingencies associated with litigation, claims or assessments have been accrued at December 31, 2013 or 2012. While the outcome of these lawsuits and claims cannot be predicted with certainty, it is the opinion of the Company's management that the loss for any litigation matters and claims that are reasonably possible to occur will not have a material adverse effect, individually or in the aggregate, on its consolidated financial position, cash flows or results of operations.

14. OIL AND GAS ACTIVITIES

The Company's oil and gas activities for 2013, 2012 and 2011 were entirely within the United States. Costs incurred in oil and gas producing activities were as follows (in thousands):

	Year Ended December 31,		
	2013	2012	2011
Development (1)	$ 2,132,824	$ 1,667,182	$ 1,245,150
Proved property acquisition	232,572	19,785	4,324
Unproved property acquisition	174,103	119,175	191,482
Exploration	363,234	436,084	400,823
Total	$ 2,902,733	$ 2,242,226	$ 1,841,779

(1) During 2013, 2012 and 2011, non-cash additions to oil and gas properties of $29.8 million, $36.3 million and $4.9 million, respectively, which relate to estimated costs of the future plugging and abandonment of the Company's oil and gas wells, are included in development costs in the table above.

Exploratory well costs that are incurred and expensed in the same annual period have not been included in the table below. The net changes in capitalized exploratory well costs were as follows (in thousands):

	Year Ended December 31,		
	2013	2012	2011
Beginning balance at January 1	$ 108,861	$ 90,519	$ 4,434
Additions to capitalized exploratory well costs pending the determination of proved reserves	281,951	384,223	354,962
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(291,962)	(358,625)	(267,847)
Capitalized exploratory well costs charged to expense	(13,472)	(7,256)	(1,030)
Ending balance at December 31	$ 85,378	$ 108,861	$ 90,519

At December 31, 2013, the Company had $10.3 million of capitalized exploratory well costs related to one well that was in progress for a period of greater than one year after the completion of drilling. This well is located in the Company's Rocky Mountains region. Of the $10.3 million in costs capitalized for this exploratory well, $7.7 million and $2.6 million were incurred in 2013 and 2012, respectively. Due to the high nitrogen and CO2 content resident in the natural gas produced by this well, processing is required before this well's gas can be sold. Before Whiting can begin building a CO2 removal and compression skid and gas pipeline for this well, however, the Company needs to first determine if there are sufficient quantities of natural gas reserves in this field to make the construction of gas processing facilities economically justifiable. As a result, the Company is continuing to drill additional wells in this area to delineate the field and to make a determination as to the aggregate quantity of natural gas reserves that can be produced from this reservoir.

15. DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

For all years presented our independent petroleum engineers independently estimated all of the proved, probable and possible reserve quantities included in this annual report. In connection with our external petroleum engineers performing their independent reserve estimations, we furnish them with the following information that they review: (1) technical support data, (2) technical analysis of geologic and engineering support information, (3) economic and production data and (4) our well ownership interests. The independent petroleum engineers, Cawley, Gillespie & Associates, Inc., evaluated 100% of our estimated proved reserve quantities and their related pre-tax future net cash flows as of December 31, 2013. Proved reserve estimates included herein conform to the definitions prescribed by the U.S. Securities and Exchange Commission. Estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

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As of December 31, 2013, all of the Company's oil and gas reserves are attributable to properties within the United States. A summary of the Company's changes in quantities of proved oil and gas reserves for the years ended December 31, 2011, 2012 and 2013 are as follows:

	Oil (MBbl)	NGLs (MBbl)	Natural Gas (MMcf)	Total (MBOE)
Balance—January 1, 2011	224,196	30,082	303,544	304,869
Extensions and discoveries	39,660	5,024	23,211	48,552
Sales of minerals in place	(579)	(632)	(9,759)	(2,837)
Purchases of minerals in place	114	58	1,639	445
Production	(18,299)	(2,074)	(26,443)	(24,780)
Revisions to previous estimates	15,052	5,151	(7,217)	19,000
Balance—December 31, 2011	260,144	37,609	284,975	345,249
Extensions and discoveries	68,134	6,526	40,915	81,479
Sales of minerals in place	(7,960)	(320)	(13,987)	(10,611)
Production	(23,139)	(2,766)	(25,827)	(30,209)
Revisions to previous estimates	4,106	(951)	(61,812)	(7,148)
Balance—December 31, 2012	301,285	40,098	224,264	378,760
Extensions and discoveries	88,293	9,830	63,893	108,772
Sales of minerals in place	(36,992)	(4,777)	(12,411)	(43,838)
Purchases of minerals in place	14,543	1,311	7,751	17,146
Production	(27,035)	(2,821)	(26,917)	(34,342)
Revisions to previous estimates	7,327	1,228	20,934	12,044
Balance—December 31, 2013	347,421	44,869	277,514	438,542
Proved developed reserves:				
December 31, 2010	160,088	18,321	220,530	215,164
December 31, 2011	180,975	22,109	211,297	238,300
December 31, 2012	190,845	24,204	160,893	241,864
December 31, 2013	198,204	23,721	183,129	252,446
Proved undeveloped reserves:				
December 31, 2010	64,108	11,761	83,014	89,705
December 31, 2011	79,169	15,500	73,678	106,949
December 31, 2012	110,440	15,894	63,371	136,896
December 31, 2013	149,217	21,148	94,385	186,096

Notable changes in proved reserves for the year ended December 31, 2013 included:

- Extensions and discoveries. In 2013, total extensions and discoveries of 108.8 MMBOE were primarily attributable to successful drilling in the Redtail, Sanish, Missouri Breaks, Hidden Bench and Pronghorn fields. The new producing wells in these areas and their related proved undeveloped locations added during the year increased the Company's proved reserves.

- Sales of minerals in place. In 2013, total sales of minerals in place of 43.8 MMBOE were primarily attributable to the disposition of the Postle Properties, further described in the Acquisitions and Divestitures footnote, which decreased the Company's proved reserves.

- Purchases of minerals in place. In 2013, total purchases of minerals in place of 17.1 MMBOE were primarily attributable to the acquisition of 121 producing oil and gas wells and undeveloped acreage in the Williston Basin, further described in the Acquisitions and Divestitures footnote, which increased the Company's proved reserves.

- Revisions to previous estimates. In 2013, revisions to previous estimates increased proved developed and undeveloped reserves by a net amount of 12.0 MMBOE. Included in these revisions were (i) 4.9 MMBOE of upward adjustments caused by higher crude oil and natural gas prices incorporated into the Company's reserve estimates at December 31, 2013 as compared to December 31, 2012 and (ii) 7.1 MMBOE of net upward adjustments attributable to reservoir analysis and well performance.

Notable changes in proved reserves for the year ended December 31, 2012 included:

- Extensions and discoveries. In 2012, total extensions and discoveries of 81.5 MMBOE were primarily attributable to successful drilling in the Sanish, Redtail, Missouri Breaks and Pronghorn fields. The new producing wells in these fields and their related proved undeveloped locations added during the year increased the Company's proved reserves.

- Revisions to previous estimates. In 2012, revisions to previous estimates decreased proved developed and undeveloped reserves by a net amount of 7.1 MMBOE. Included in these revisions were (i) 11.8 MMBOE of downward adjustments caused by lower crude oil and natural gas prices incorporated into the Company's reserve estimates at December 31, 2012 as compared to December 31, 2011, and (ii) 4.7 MMBOE of net upward adjustments attributable to reservoir analysis and well performance.

Notable changes in proved reserves for the year ended December 31, 2011 included:

- Extensions and discoveries. In 2011, total extensions and discoveries of 48.6 MMBOE were primarily attributable to successful drilling in the Sanish and Pronghorn fields. The new producing wells in these fields and their related proved undeveloped locations added during the year increased the Company's proved reserves in these areas.

- Revisions to previous estimates. In 2011, revisions to previous estimates increased proved developed and undeveloped reserves by a net amount of 19.0 MMBOE. Included in these revisions were (i) 4.7 MMBOE of upward adjustments caused by higher crude oil prices incorporated into the Company's reserve estimates at December 31, 2011 as compared to December 31, 2010, and (ii) 14.3 MMBOE of net upward adjustments attributable to reservoir analysis and well performance. The oil component of the net 14.3 MMBOE revision consisted of a 10.9 MMBOE increase that was primarily related to the Postle and North Ward Estes fields, where the performance of the CO2 injection EOR projects supported an increase in the proved reserve assignments. The NGL component of the net 14.3 MMBOE revision consisted of a 4.8 MMBOE increase due to the performance of the Postle and North Ward Estes fields and various properties in the Northern Rockies area, primarily in the Sanish field. The gas component of the net 14.3 MMBOE revision consisted of a 1.4 MMBOE decrease that was primarily related to the Flat Rock field where proved reserve assignments were reduced due to the production performance of two recently completed wells.

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As discussed in Deferred Compensation within these footnotes to the consolidated financial statements, all of the Company's employees participate in the Company's Production Participation Plan (the "Plan"). The reserve disclosures above include oil and natural gas reserve volumes that have been allocated to the Plan. Once allocated to Plan participants, the interests are fixed. Allocations prior to 1995 consisted of 2%–3% overriding royalty interest, while allocations since 1995 have been 1.75%–5% of oil and gas sales less lease operating expenses and production taxes from the production allocated to the Plan.

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves and the changes in standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves were prepared in accordance with the provisions of FASB ASC Topic 932, Extractive Activities—Oil and Gas. Future cash inflows as of December 31, 2013, 2012 and 2011 were computed by applying average fiscal-year prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period ended December 31, 2013, 2012 and 2011, respectively) to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year end, based on year-end costs and assuming the continuation of existing economic conditions.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves, less the tax basis of properties involved. Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation does not necessarily result in an estimate of the fair value of the Company's oil and gas properties.

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

	December 31,		
	2013	2012	2011
Future cash flows	$ 35,178,399	$ 29,308,752	$ 26,815,086
Future production costs	(12,973,292)	(11,397,332)	(8,908,131)
Future development costs	(5,355,383)	(3,181,618)	(1,982,813)
Future income tax expense	(3,954,401)	(4,278,529)	(4,875,973)
Future net cash flows	12,895,323	10,451,273	11,048,169
10% annual discount for estimated timing of cash flows	(6,301,462)	(5,044,240)	(5,775,677)
Standardized measure of discounted future net cash flows	$ 6,593,861	$ 5,407,033	$ 5,272,492

Future cash flows as shown above are reported without consideration for the effects of open hedge contracts at each period end. If the effects of hedging transactions were included in the computation, then undiscounted future cash inflows would not have changed in 2013 and would have decreased by $20.2 million and $50.7 million in 2012 and 2011, respectively.

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

	December 31,		
	2013	2012	2011
Beginning of year	$ 5,407,033	$ 5,272,492	$ 3,667,606
Sale of oil and gas produced, net of production costs	(2,010,925)	(1,589,665)	(1,415,469)
Sales of minerals in place	(1,064,195)	(438,614)	(67,600)
Net changes in prices and production costs	902,916	(1,061,495)	2,246,014
Extensions, discoveries and improved recoveries	2,827,321	3,708,780	1,156,740
Previously estimated development costs incurred during the period	832,096	526,982	408,079
Changes in estimated future development costs	(1,264,189)	(1,498,592)	(797,542)
Purchases of minerals in place	445,669	-	10,604
Revisions of previous quantity estimates	313,069	(295,432)	452,668
Net change in income taxes	(335,637)	255,328	(755,369)
Accretion of discount	540,703	527,249	366,761
End of year	$ 6,593,861	$ 5,407,033	$ 5,272,492

Future net revenues included in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves incorporate calculated weighted average sales prices (inclusive of adjustments for quality and location) in effect at December 31, 2013, 2012 and 2011 as follows:

	2013	2012	2011
Oil (per Bbl)	$ 90.80	$ 87.15	$ 89.18
NGLs (per Bbl)	$ 54.38	$ 58.15	$ 62.93
Natural Gas (per Mcf)	$ 4.30	$ 3.21	$ 4.39

16. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited quarterly financial data for the years ended December 31, 2013 and 2012 (in thousands, except per share data):

	Three Months Ended			
Year ended December 31, 2013:	March 31, 2013	June 30, 2013	September 30, 2013	December 31, 2013
Oil, NGL and natural gas sales	$ 605,114	$ 651,868	$ 706,543	$ 703,024
Operating profit (1)	$ 252,806	$ 269,528	$ 316,764	$ 280,311
Net income (loss)	$ 86,244	$ 134,944	$ 204,091	$ (59,276)
Basic earnings (loss) per share	$ 0.73	$ 1.14	$ 1.72	$ (0.50)
Diluted earnings (loss) per share	$ 0.72	$ 1.14	$ 1.71	$ (0.50)

Year ended December 31, 2012:	Three Months Ended March 31, 2012	June 30, 2012	September 30, 2012	December 31, 2012
Oil, NGL and natural gas sales	$ 558,697	$ 492,756	$ 521,195	$ 565,066
Operating profit (1)	$ 263,176	$ 201,900	$ 204,230	$ 235,635
Net income	$ 98,446	$ 150,851	$ 83,113	$ 81,689
Basic earnings per share	$ 0.84	$ 1.28	$ 0.70	$ 0.69
Diluted earnings per share	$ 0.83	$ 1.27	$ 0.70	$ 0.69

(1) Oil, NGL and natural gas sales less lease operating expense, production taxes and depreciation, depletion and amortization.

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of disclosure controls and procedures. In accordance with Rule 13a-15(b) of the Securities Exchange Act of 1934 (the "Exchange Act"), our management evaluated, with the participation of our Chairman and Chief Executive Officer and our Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of the end of the year ended December 31, 2013. Based upon their evaluation of these disclosures controls and procedures, the Chairman and Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures were effective as of the end of the year ended December 31, 2013 to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission, and to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control Over Financial Reporting. The management of Whiting Petroleum Corporation and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Our internal control over financial reporting is 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.

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

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2013 using the criteria set forth in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management believes that, as of December 31, 2013, our internal control over financial reporting was effective based on those criteria.

The effectiveness of our internal control over financial reporting as of December 31, 2013 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein on the following page.

Changes in internal control over financial reporting. There was no change in our internal control over financial reporting that occurred during the quarter ended December 31, 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Whiting Petroleum Corporation
Denver, Colorado

We have audited the internal control over financial reporting of Whiting Petroleum Corporation and subsidiaries (the "Company") as of December 31, 2013, based on criteria established in Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual 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 by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2013 of the Company and our report dated February 27, 2014 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 27, 2014

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information included under the captions "Election of Directors," "Board of Directors and Corporate Governance" and "Section 16(a) Beneficial Ownership Reporting Compliance" in our definitive Proxy Statement for Whiting Petroleum Corporation's 2014 Annual Meeting of Stockholders (the "Proxy Statement") is incorporated herein by reference. Information with respect to our executive officers appears in Part I of this Annual Report on Form 10-K.

We have adopted the Whiting Petroleum Corporation Code of Business Conduct and Ethics that applies to our directors, our Chairman and Chief Executive Officer, our Chief Financial Officer, our Controller and Treasurer and other persons performing similar functions. We have posted a copy of the Whiting Petroleum Corporation Code of Business Conduct and Ethics on our website at www.whiting.com. The Whiting Petroleum Corporation Code of Business Conduct and Ethics is also available in print to any stockholder who requests it in writing from the Corporate Secretary of Whiting Petroleum Corporation. We intend to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding amendments to, or waivers from, the Whiting Petroleum Corporation Code of Business Conduct and Ethics by posting such information on our website at www.whiting.com.

We are not including the information contained on our website as part of, or incorporating it by reference into, this report.

Item 11. Executive Compensation

The information required by this Item is included under the captions "Board of Directors and Corporate Governance – Compensation Committee Interlocks and Insider Participation," "Board of Directors and Corporate Governance – Director Compensation," "Compensation Discussion and Analysis," "Compensation Committee Report" and "Executive Compensation" in the Proxy Statement and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this Item with respect to security ownership of certain beneficial owners and management is included under the caption "Principal Stockholders" in the Proxy Statement and is incorporated herein by reference. The following table sets forth information with respect to compensation plans under which equity securities of Whiting Petroleum Corporation are authorized for issuance as of December 31, 2013.

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Equity Compensation Plan Information

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights		Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in the first column)	
Equity compensation plans approved by security holders (1)	420,840	$	28.65	5,380,594	(2)
Equity compensation plans not approved by security holders	-		N/A	-	
Total	420,840	$	28.65	5,380,594	(2)

(1) Includes the Whiting Petroleum Corporation 2003 Equity Incentive Plan (the “2003 Plan”) and Whiting Petroleum Corporation 2013 Equity Incentive Plan (the “2013 Plan”). Upon shareholder approval of the 2013 Plan in May 2013, the 2003 Plan was terminated, but continues to govern awards that were outstanding on its termination. Any shares netted or forfeited under the 2003 Plan will be available for future issuance under the 2013 Plan.

(2) Number of securities reduced by 420,840 stock options outstanding and 1,444,310 shares of restricted common stock previously issued for which the restrictions have not lapsed.

Item 13. Certain Relationships, Related Transactions and Director Independence

The information required by this Item is included under the caption “Board of Directors and Corporate Governance – Transactions with Related Persons” and “Board of Directors and Corporate Governance – Independence of Directors” in the Proxy Statement and is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

The information required by this Item is included under the caption “Ratification of Appointment of Independent Registered Public Accounting Firm” in the Proxy Statement and is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) 1. Financial statements – Refer to the Index to Consolidated Financial Statements included in Item 8 of this Form 10-K for a list of all financial statements filed as part of this report.

2. Financial statement schedules – The following financial statement schedule is filed as part of this Annual Report on Form 10-K:

a. Schedule I – Condensed Financial Information of Registrant

All other schedules are omitted since the required information is not present, or is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the consolidated financial statements or the notes thereto.

3. Exhibits – The exhibits listed in the accompanying index to exhibits are filed as part of this Annual Report on Form 10-K.

(b) Exhibits

The exhibits listed in the accompanying exhibit index are filed (except where otherwise indicated) as part of this report.

(c) Financial Statement Schedules

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SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT

WHITING PETROLEUM CORPORATION
CONDENSED FINANCIAL STATEMENTS OF THE PARENT COMPANY

CONDENSED BALANCE SHEETS
(in thousands)

	December 31, 2013	December 31, 2012
ASSETS		
Current assets	$ 5,120	$ 2,390
Investment in subsidiaries	2,707,184	2,330,987
Intercompany receivable	3,796,321	1,748,463
Total assets	$ 6,508,625	$ 4,081,840
LIABILITIES AND EQUITY		
Current liabilities	$ 26,054	$ 14,372
Long-term debt	2,653,834	600,000
Other long-term liabilities	170	21,244
Shareholders’ equity	3,828,567	3,446,224
Total liabilities and equity	$ 6,508,625	$ 4,081,840

CONDENSED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(in thousands)

	Year Ended December 31, 2013	2012	2011
Operating expenses:			
General and administrative	$ (1,131)	$ (16,506)	$ (12,024)
Interest expense	(2,922)	(2,168)	(2,066)
Equity in earnings of subsidiaries	361,732	425,870	500,564
Income before income taxes	357,679	407,196	486,474
Income tax benefit	8,376	6,993	5,213
Net income	$ 366,055	$ 414,189	$ 491,687
Comprehensive income	$ 366,055	$ 414,189	$ 491,687

See notes to condensed financial statements.

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Schedule I

WHITING PETROLEUM CORPORATION
CONDENSED FINANCIAL STATEMENTS OF THE PARENT COMPANY

CONDENSED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2013	2012	2011
Cash flows provided by operating activities	$ -	$ 16,423	$ 4,962
Cash flows from investing activities:			
Investment in subsidiaries	-	-	-
Cash flows from financing activities:			
Intercompany receivable	(2,048,253)	(14,094)	(3,091)
Issuance of 5% Senior Notes due 2019	1,100,000	-	-
Issuance of 5.75% Senior Notes due 2021	1,204,000	-	-
Redemption of 7% Senior Subordinated Notes due 2014	(253,988)	-	-
Other financing activities	(1,759)	(2,329)	(1,871)
Net cash used in financing activities	-	(16,423)	(4,962)
Net change in cash and cash equivalents	-	-	-
Cash and cash equivalents:			
Beginning of period	-	-	-
End of period	$ -	$ -	$ -
NONCASH INVESTING ACTIVITIES:			
Distributions from Whiting USA Trust I decreasing investment in subsidiaries	$ (4,749)	$ (5,827)	$ (6,500)

See notes to condensed financial statements.

(Continued)

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Schedule I

WHITING PETROLEUM CORPORATION
CONDENSED FINANCIAL STATEMENTS OF THE PARENT COMPANY

CONDENSED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2013	2012	2011
NONCASH FINANCING ACTIVITIES:			
Preferred stock dividends paid decreasing shareholders' equity	$ (538)	$ (1,077)	$ (1,077)
Preferred stock dividends paid decreasing intercompany receivable	$ (538)	$ (1,077)	$ (1,077)
Distributions from Whiting USA Trust I increasing intercompany receivable	$ 4,749	$ 5,827	$ 6,500

See notes to condensed financial statements.

(Concluded)

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WHITING PETROLEUM CORPORATION
NOTES TO CONDENSED FINANCIAL STATEMENTS OF THE PARENT COMPANY

1. BASIS OF PRESENTATION

Condensed Financial Statements—The condensed financial statements of Whiting Petroleum Corporation (the "Registrant" or "Parent Company") do not include all of the information and notes normally included with financial statements prepared in accordance with GAAP. These condensed financial statements, therefore, should be read in conjunction with the consolidated financial statements and notes thereto of the Registrant, included elsewhere in this Annual Report on Form 10-K. For purposes of these condensed financial statements, the Parent Company's investments in wholly-owned subsidiaries are accounted for under the equity method.

Restricted Assets of Registrant—Except for limited exceptions, including the payment of interest on the senior notes and senior subordinated notes, Whiting Oil and Gas Corporation's ("Whiting Oil and Gas") credit agreement restricts the ability of Whiting Oil and Gas to make any dividend payments, distributions or other payments to the Parent Company. As of December 31, 2013, total restricted net assets were $4,070.4 million. Accordingly, these condensed financial statements have been prepared pursuant to Rule 5-04 of Regulation S-X of the Securities Exchange Act of 1934, as amended.

2. LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

The Parent Company's long-term debt and other long-term liabilities consisted of the following at December 31, 2013 and 2012 (in thousands):

	December 31, 2013	December 31, 2012
Long-term debt:		
7% Senior Subordinated Notes due 2014	$ -	$ 250,000
6.5% Senior Subordinated Notes due 2018	350,000	350,000
5% Senior Notes due 2019	1,100,000	-
5.75% Senior Notes due 2021, including unamortized debt premium of $3,834	1,203,834	-
Other long-term liabilities:		
Tax sharing liability (1)	-	21,074
Other	170	170
Total long-term debt and other long-term liabilities	$ 2,654,004	$ 621,244

(1) As of December 31, 2013, the entire $23.9 million balance due to Alliant Energy under the tax sharing agreement was reflected as a current liability in these condensed financial statements and is included in the schedule of maturities below.

Scheduled maturities of the Parent Company's principal amounts of long-term debt and other long-term liabilities (including the current portions thereof) as of December 31, 2013 were as follows (in thousands):

	2014	2015	2016	2017	2018	Thereafter	Total
Amounts due	$ 23,856	$ -	$ -	$ -	$ 350,000	$ 2,300,000	$ 2,673,856

For further information on the Senior Subordinated Notes, Senior Notes and tax sharing liability, refer to the Long-Term Debt and Related Party Transactions notes to the consolidated financial statements of the Registrant.

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3. SHAREHOLDERS' EQUITY

Common Stock—In May 2011, the Registrant's stockholders approved an amendment to its Restated Certificate of Incorporation to increase the number of authorized shares of common stock from 175,000,000 shares to 300,000,000 shares.

Stock Split. On January 26, 2011, the Board of Directors approved a two-for-one split of the Registrant's shares of common stock to be effected in the form of a stock dividend. As a result of the stock split, stockholders of record on February 7, 2011 received one additional share of common stock for each share of common stock held. The additional shares of common stock were distributed on February 22, 2011. The common stock dividend resulted in the conversion price for Parent Company's 6.25% Convertible Perpetual Preferred Stock being adjusted from $43.4163 to $21.70815.

6.25% Convertible Perpetual Preferred Stock—In June 2009, the Parent Company completed a public offering of 6.25% convertible perpetual preferred stock ("preferred stock"), selling 3,450,000 shares at a price of $100.00 per share. As a result of voluntary conversions and the Parent Company exercising its right to mandatorily convert shares of preferred stock effective June 27, 2013, all 172,129 shares of preferred stock outstanding on March 31, 2013, were converted into 792,919 shares of common stock. As of December 31, 2013, no shares of preferred stock remained outstanding.

For further information on the common stock and convertible perpetual preferred stock, refer to the Shareholders' Equity note to the consolidated financial statements of the Registrant.

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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, on this 27th day of February, 2014.

WHITING PETROLEUM CORPORATION

By /s/ James J. Volker
James J. Volker
Chairman and Chief Executive Officer

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

Signature	Title	Date
/s/ James J. Volker James J. Volker	Chairman and Chief Executive Officer and Director (Principal Executive Officer)	February 27, 2014
/s/ Michael J. Stevens Michael J. Stevens	Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2014
/s/ Brent P. Jensen Brent P. Jensen	Controller and Treasurer (Principal Accounting Officer)	February 27, 2014
/s/ Thomas L. Aller Thomas L. Aller	Director	February 27, 2014
/s/ D. Sherwin Artus D. Sherwin Artus	Director	February 27, 2014
/s/ Philip E. Doty Philip E. Doty	Director	February 27, 2014
/s/ William N. Hahne William N. Hahne	Director	February 27, 2014
	Director	February 27, 2014

/s/ Allan R. Larson Allan R. Larson		
/s/ Michael B. Walen Michael B. Walen	Director	February 27, 2014

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EXHIBIT INDEX

Exhibit Number	Exhibit Description
(3.1)	Restated Certificate of Incorporation of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 3.2 to Whiting Petroleum Corporation's Current Report on Form 8-K dated June 28, 2013 (File No. 001-31899)].
(3.2)	Amended and Restated By-laws of Whiting Petroleum Corporation, effective February 20, 2014 [Incorporated by reference to Exhibit 3.1 to Whiting Petroleum Corporation's Current Report on Form 8-K dated February 20, 2014 (File No. 001-31899)].
(4.1)	Fifth Amended and Restated Credit Agreement, dated as of October 15, 2010, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and the various other agents party thereto [Incorporated by reference to Exhibit 4 to Whiting Petroleum Corporation's Current Report on Form 8-K dated October 15, 2010 (File No. 001-31899)].